LEAST COST GENERATION EXPANSION PLANNING FOR NORTHERN REGION ELECTRICITY BOARD NETWORK CONSIDERING GREENHOUSE GAS MITIGATION

by
ULLASH KUMAR ROUT

DEPARTMENT OF ELECTRICAL ENGINEERING
INDIAN INSTITUTE OF TECHNOLOGY KANPUR

May, 2000

LEAST COST GENERATION EXPANSION PLANNING FOR NORTHERN REGIONAL ELECTRICITY BOARD NETWORK CONSIDERING GREENHOUSE GAS MITIGATION

A thesis submitted
in partial fulfillment of the requirements
for the degree of
MASTER OF TECHNOLOGY

by
ULLASH KUMAR ROUT

to the
DEPARTMENT OF ELECTRICAL ENGINEERING
INDIAN INSTITUTE OF TECHNOLOGY, KANPUR
MAY 2000

CERTIFICATE

This is to certify that the thesis entitled *Least cost generation expansion planning for Northern Regional Electricity Board network considering greenhouse gas mitigation* submitted by Ullash Kumar Rout to Indian Institute of Technology Kanpur for the award of Master of Technology degree in Electrical Engineering is a bonafide record of project work carried out under my supervision Contents of the thesis in full or in parts have not been submitted to any other institute or university for the award of degree or diploma

Dr S C Srivastava
Professor
Department of Electrical Engineering
Indian Institute of Technology
Kanpur India

ACKNOWLEDGEMENT

The author would like to express his deep appreciation and gratitude to his thesis supervisor Professor S C Srivastava for his invaluable guidance and constant encouragement through out the course of this project His love help encouragement and guidance will remain forever in my memory

The author is thankful to the faculty members of the department of electrical engineering I I T Kanpur who taught and helped in understanding various courses in electrical engineering

This thesis is part of the project number AIT/EE/19990071 and 19990098 jointly carried out by I I T Kanpur and CEA New Delhi and sponsored by Swedish International Development Agency (Sida) and Asian Institute of Technology Thailand Financial support under this project for carrying out the present work is duly acknowledged

The author also duly acknowledge Mr Dharam Paul and Mr Praveen Gupta from CEA New Delhi and Dr Ram Shrestha from AIT Thailand for various inputs provided by them to carry out the present work He also acknowledge Dr Mukesh Sharma from civil department and Dr Binayak Rath from HSS department

The author is deeply grateful to his close friends Anurag Biranchi Sibapada Chand Ravindra Asesh and Tanmaya whose constant support and encouragement have gone a long way towards the successful completion of this work

Finally the author wish to record his deep sense of gratitude to his parents sisters brother in-laws brother father and mother in laws and his wife whose constant encouragement and inspiration is behind his education

Table of Contents

List of Tables

Table No	Description	Page

List of Figures

Abstract

The electricity energy is the key to the economic growth and improving the living standard of a country In most of the Asian countries particularly in India there is shortage of enough generating plants to meet the required peak demand Continuous addition of power plants require the generation expansion planning to be carried out at regular intervals The traditional generation expansion planning has been based on the least cost strategy Increased awareness to both the local and global environmental problems has forced the planners to include various mitigation criteria in the generation expansion planning also In the present thesis at attempt has been made to include greenhouse gas mitigation especially carbon dioxide in the planning methodology The study has been carried out on one of the five regional electricity boards of India i e the Northern Regional Electricity Board (NREB) network

For the present generation expansion planning study three alternative scenarios have been considered These are the least cost generation expansion planning least cost generation expansion planning with the efficient technologies and the least cost generation expansion planning with mitigation of Greenhouse Gas (GHG) as constraint Emission mitigation target of 5% and 10% have been considered over the conventional least cost generation expansion planning results Various sensitivity analyses have been carried out for the above three cases with the variation different parameters such as discount rate fuel prices power demand supply side capital cost and the efficiency of the efficient technologies

The result shows that the least cost generation is possible with the installation of efficient technologies i e the PFBC and IGCC This also reduces the emission levels The emission mitigation target can be fulfilled by the installation of more number of CCGT and nuclear plants The power generation from these plants are some what costlier than the PFBC and IGCC plants

CHAPTER-1

INTRODUCTION

1 1 General Introduction

Energy demand and electricity use is growing more rapidly in most of the developing countries than in Industrialized nations Energy has been a major drive for all economies The per capita energy consumption is considered as an index of standard of living of the persons in a country Electricity is vital for all sectors of the national economy It is one of the principal production factors in the domestic sector to satisfy the enhancement of the basic need of human being As electrical energy is the key to the national economy the energy demand by the consumers should be fulfilled by the power sector with least cost Economic growth and balanced socio economic developments are closely related to the development of the electric power sector and national economic development programs must be supported by studies on electric power sector planning

As the modern world is undergoing the scientific and industrial revolution the necessity of commercial energy is increasing rather than the non commercial energy The non commercial energy demand is decreasing and the total reserve and potential of the non commercial energy resources is also decreasing day by day In India the population growth rate (which is much more than the world average) is the prime cause of reduction of non commercial energy resources The demand of electrical energy ahs been popular as it can be easily converted in to different forms such as light sound thermal electromagnetic mechanical etc The conversion efficiency of electrical energy to other forms of energy is high and the cost of conversion is low The other advantage is that it is easily transportable and transferable Due to the above

advantages the world seeks the help of electrical energy and trying to exploit the better facilities from it

Fossil fuels are the major source in producing electricity Currently around 40 percent of the world electricity generation are coming from the fossil fuel power plants It is estimated that the energy sector contributes approximately 50 percent of the total emission to the environment In energy sector thermal power plants are the main source of emission It is approximated that thermal sector contributes 30 to 35 percent of total emission alone [54] The trend of power generation is not likely to change in near future This may increase level of Greenhouse Gas (GHG) concentration in the environment and other pollutants

Global warming and acid rains are the burning issues world wide these days Due to increase in population deforestation and pacing of world to wards modernization the increase in pollution level in atmosphere is drawing the attention of world community Global warming is due to accumulation of Green House Gases (GHGs) in the atmosphere Carbon dioxide methane sulphur hexafluoride chlorofluoro carbons hydrofluoro carbons perfluoro carbons nitrous oxide are some of the greenhouse gases The GHG traps the heat radiation and increases the temperature of atmosphere The polar ice caps will melt due to the rise in temperature of atmosphere and the rise in sea level will cause the submerge of low level lands through out the world The GHG depletes the layer of ozone which is acting as the filter layer for harmful radiation to earth

The acid rain is another endangering phenomena to our healthy environment It is due to the sulfuric and nitric acid whose level increases due to emission of nitrogen oxide (NOx) and sulphur dioxide (SO_2) from the burning of more quantity of fossil fuels

Recently the efforts are going on in the industrialized world to reduce GHG from their power sector by the demand and supply-side management

1 2 Literature Review

A large variety of non commercial forms of energy such as fuel wood animal waste and agricultural residues fulfill the 97% of the total energy requirement of rural India and its contribution has declined from over 70% in the early 1950s to 28% in 1998 [49] This shift in consumption from traditional to commercial energy results from the shift of the traditional fuels like bio mass and animal waste towards cleaner and the modern fuels like kerosene and liquefied petroleum gas fast pace of urbanization and higher living standards associated with rising per capita income The total energy consumption of energy (commercial as well as non commercial) is related to the demographic parameters such as population and structure of gross domestic product (GDP)

Electricity generation in Asia as a whole is expected to increase at a higher rate than the global average [26] The electricity generation is predominantly based on thermal power plants (i e more than 70% of the total power generation is thermal) in most Asian countries [50] The share of the thermal power is likely to increase further in the coming years For example the share of thermal electricity generation is expected to increase from 78% in 2000 to 81% in 2010 in the case of India and from 94%in 2000 to 96% in 2010 in the case of Thailand [8 17] The thermal power growth percentage will be more in the countries like India Indonesia Malaysia Thailand and Pakistan However in China the percentage of thermal power generation will decrease due to the construction of large hydro plants such as 18200MW hydro power plant on the river Changjiang In Asian countries like India China Indonesia and Malaysia coal is the dominant fuel used for power generation [8 4 15]

Electrification rate is low in selected Asian countries For example electrification rate is 27% in Sri Lanka and 24% in Indonesia (in 1990) About 69% and 83% of house holds were electrified in provincial and metropolitan areas in Thailand in 1990 (ADB 1993) while 27% of rural households in India has access to electricity [8] India should give importance to produce more power and electrify the rural areas

About two decades ago utilities made substantial efforts to reduce particulate emissions from power generation by investing in electrostatic preceptor filters and wet scrubbers To reduce the emissions from the power plants the engineers follow different methods Flue Gas Desulphurisation (FGD) pre combustion and post combustion technologies are used to reduce the SO_2 from the power sector Special burners are used to burn the coal at low temperature and sprinkling of water reduces the NO_x emission Washing coals clean coal technologies and different methods are followed to reduce the CO_2 emissions [2]

Power plant emits different local and global pollutants as the combustion of coal oil gas etc used for the power generation The combustion of such fuels increases the pollution level Among the fossil fuels the natural gas is the cleanest source and environmental friendly New combined cycle power plants emit half of the carbon dioxide (CO_2) one fifth of the nitrogen oxide (NO_x) and almost negligible amount of sulphur dioxide (SO_2) compared to a comparable sized coal fired power plant [34 55]

The efficiency of thermal plants are around 30% in the developing countries where as the efficiency is more than 35% in developed countries It occurs due to the adoption of new technologies and the availability of more capital investment Though the efficiency of gas based plants are below some of the thermal power plants most electric utilities opt for the gas turbine power plants due to its known features of low capital cost high flexibility high reliability short delivery time less construction time and fast starting and load pick up Installing a steam plant with the gas plant can further expand another advantage that the gas based plant s flue gas heat wastage can be used for the steam generation The efficiency of the combined cycle plant is more than the steam plant and gas plant The overall efficiency of this type of plant may be up to 55% [46]

Fossil fuels contain organic sulphur and pyretic sulphur During combustion the sulphur compounds goes to the atmosphere Sulphur dioxide and nitrogen oxides are the two major pollutants for the acid rain Due to this the p_H value of the earth surface changes Shrestha and Acharya (1992) have estimated the emission of different

pollutants from the thermal power generation sector for the various Asian countries Plinke et al (1992) have discussed different options to reduce the emission of trace gases like fuel switching technology substitution measures clean coal technologies and emission control technologies Shrestha and Bhattacharya (1991) have discussed different methods to reduce the emission of SO_2 at different stages during the combustion of coal like pre combustion (coal cleaning) during combustion (fluidized and circulating fluidized bed combustors) and post combustion (flue gas desulfurization)

There are broadly two categories of options to improve the environmental performance of power sector These are

a) Supply side options which include

- Emission controls in power generation Improvement in power generation efficiency
- Reduction of system losses
- Hydro power development
- Fuel switching in power generation

b) Demand side options which include

- Efficient electricity pricing and
- End use efficiency improvement

The concentration of the CO_2 one of the greenhouse gases in the atmosphere is increasing from the starting of industrial revolution Atmospheric CO_2 increased by 25% from 280 PPM (in 1750) to 350 PPM (in 1990) and this process has been accelerated during the last 50 years The reduction of the GHG emissions has become a prime environmental goal to be persuaded on a global level Different authors have discussed about the emission of CO_2 associated with the different sectors of the economy e g William (1993) Groscurth and Kummel (1990) Hippel et al (1990) etc

The power sector is the major contributor of CO_2 For example the share of power sector in total carbon dioxide emission was estimated to be 45% in India 33% in

China and 31% in Thailand in 1995 [19] As the thermal power plants are increasing in Asian countries it is obvious that the share in CO_2 emission is expected to grow in these countries The CO_2 emission from the power sector in China India and Thailand are projected to grow at the rates of about 6 0 8 9 and 8 7 percent per annum respectively from 2000 to 2010 [27 58 8] Coal as a fuel used for power generation in Asian countries such as China India Indonesia and Malaysia Thailand and is considered to be the largest source of CO_2 and other harmful emissions Therefore the growth of the power sector in the Asian countries has implication for both green house gases emission and other harmful emissions (e g SO_2 and NO_x) that adversely effect the global and local environment

Although there are no abatement techniques available for CO_2 emission however following options can be used for reducing CO_2 emissions [31]

1 Energy conversion and development of new technologies to increase the efficiency of the plants
2 Substituting low carbon content of fuels
3 Introducing nuclear power plant and more hydro power plants
4 Increase the number of renewable energy sources

1 3 Generation Expansion Planning Packages

The purpose of power system planning is to meet the power demand by consumers with minimum possible cost There are various cost minimization techniques formulated in order to find the least cost generation expansion planning Recently developed packages are formulated for the minimization of both cost and environmental pollutants as the environmental emission is the burning issue in the present time Mathematical programming approaches like linear non linear mixed integer and dynamic programming are used mostly for the cost minimization of generation expansion planning There are several software simulation packages which are available for the least cost generation expansion planning with and without emission constraints Some of the important software packages are as follows [29]

- Wein Automatic System Planning Package (WASP)
- Optimization Generation Planning Package (OGP)
- Production Cost Simulation Program (PCS)
- National Investment Model (MNI)
- Integrated Resource Planning Analysis (IRPA)
- Production Cost and Reliability System for Electric Utility
- Electric Generation Expansion Analysis System (EGEAS)
- Production Cost Analysis Program (PROCOST)
- Capacity Expansion and Reliability Evaluation / Analysis System (CERAS)
- Power System Production Costing Model (POWERSYM)
- Westinghouse Interactive Generation Planning (WIGPLAN)
- RELCOMP Model
- SCOPE Model
- ICARUS Model

In this thesis the Integrated Resource Planning and Analysis (IRPA) package developed by Asian Institute of Technology Thailand has been used for the least cost analysis with the emission constraints

1 4 Power Scenario in India

India s power sector is presently managed by state electricity boards which are being assisted by central public sector generating companies their licensees and independent power producers However the distribution transmission and the supply of power to the consumers is handled by the state electricity boards The total installed capacity for India up to today is around 94 000MW comprising of around 68 000MW (thermal) 2 240MW (nuclear) 1 000MW (wind) and 22 800MW (hydro) It is given in the Annex E figure 1 With this much generating capacity India is not able to meet the peak power demand So the load shedding is exercised through out the year which is affecting the development and the economic progress of the country Hence there is an urgent need for the extension of power generation by implementing and constructing the new plants The primary resources to power generation in the country are water

fossil fuels (coal lignite oil and natural gas) and nuclear fuels The over all plant load factor (PLF) in India is 63% Country has about 93 920MW potential of pumped storage hydro plants and about 10 000MW of small hydro plant [21] Also the country has large potential for other conventional resources Such as wind power biomass tidal power ocean thermal power the potentials are 20 000MW 17 000MW 9 000MW 50 000MW and 20 000MW respectively The values are given in the Annex E figure 2 Beyond this there are geothermal sources of power The limitation of geothermal power depends on the geographical location and the number of volcano at that site or place Beyond this the solar power plant has the unlimited potential The anticipated capacity addition from various non conventional sources [22] during 9^{th} 10^{th} and 11^{th} plan are about 6 500MW 13 000MW and 19 500MW respectively In addition the co generation potential in various generic industries is about 6 500MW to 8 000MW The present nuclear power generation based on PHWR and BWR technology is 1 840MW (derated capacity) This contributes about 2 2% of the total generation in the country The Nuclear Power Corporation of India has plans to enhance the nuclear power plant capacity to 11 600MW by the end of 11^{th} plan [21]

At present the CEA New Delhi has presented its ninth national plan for the country As per the projections made by the 15^{th} electric power survey (EPS) [21] the electrical energy and peak power demand which stood at 3 89 721MU and 60 981MW during 1995 1996 are going to increase as following

Table 1 1 Peak power and Electric energy demand projection of India

Fore cast [1]	By end of 9^{th} plan (2001 2002)	By end of 10^{th} plan (2006 2007)	By end of 11^{th} plan (2011 2012)
Peak Demand	95757	130944	176647
Energy (MU)	569560	781863	1058440

State electricity boards (SEBs) Damodar valley corporation (DVC) and Bhakra Beas management board (BBMB) are presently primarily managing the power system network in India In addition to this certain licensees of the state electricity board are also generating power such as BSES/CSES/AECO Since 1991 the power generation

has been opened to all Taking this opportunities the Independent Power Producers (IPPs) are also generating the power and selling to the state electricity boards

The inter state transmission network is done by power grid corporation of India limited (PGCIL) a public sector company Power grid corporation of India Limited is solely responsible for the transmission network in the country Generation of electricity is being done by state electricity boards as well as central or statutory generating companies like National Thermal Power Corporation (NTPC) and National Hydroelectric Power corporation (NHPC) The regional grid is managed by five regional electricity boards (REBs) namely

1 Northern Regional Electricity Board (NREB) having head quarter at New Delhi
2 Southern Regional Electricity Board (SREB) having head quarter at Bangalore
3 Eastern Regional Electricity Board (EREB) having head quarter at Calcutta
4 Western Regional Electricity Board (WREB) having head quarter at Mumbai
5 North Eastern Regional electricity Board (NEREB) having head quarter at Shillong

The boards are under the administrative control of Central Electricity Authority Day to day operation of the grid is carried out by Regional Load Dispatch Centers (RLDCs) which are under Power Grid Corporation of India Limited Regional load dispatch centers function under the supervision and guidance of regional electricity boards Each state has its own power department or ministry and at the central level ministry of power overseas functioning of electricity sector

1 5 Rationale and Objective Behind the Study

The convention generation expansion planning in most of the countries are carried out using least cost criteria The increased concern about the environmental protection has necessitated to include the reduction of various types of emissions also into planning criteria Many developed and some of the developing countries have already brought out environmental protection acts to limit specifically the local pollutants However all the nations together have joint responsibility to bring down the

levels of global pollutants the most important being the Greenhouse Gases (GHGs) Thermal power plants are one of the major producers of such gases especially carbon dioxides The generation expansion planning must address to the reduction in the GHGs and incorporate emission limit in the planning package Such constraint will force the more efficient generation options to be selected No systematic work appears to have been done on quantifying the impact of including GHG mitigation constraints on the generation planning Therefore an attempt has been made in this thesis to carry out detailed analysis on impact of the GHG mitigation in generation expansion planning on a practical regional electricity board network in India

Few specific objectives of the studies carried out in this thesis have been projected

1 To analyze the least cost generation expansion planning which will fulfill the power demand by the consumers for the selected planning horizon
2 To analyze the least cost generation expansion planning with efficient supply side technologies
3 To analyze the least cost generation expansion planning with efficient supply side technologies and taking consideration of the abatement of GHG (only CO_2) by five as well as ten percent from the base value of least cost generation expansion planning
4 To carry out the sensitivity analyses for the above cases with the variation of the value of the parameters such as discount rate fuel price power demand supply side capital cost generation efficiency of a new or clean power plant

1 6 Organisation of Thesis

The present thesis has been organized into five chapters

The present **Chapter 1** introduces the generation expansion planning problem presents a brief literature survey & power scenario in India and sets the motivation behind the present work

Chapter 2 presents the methodology for traditional least cost generation expansion planning and the study results including for the sensitivity analyses on Northern Regional Electricity Board (NREB) network

Chapter 3 studies the impact of two efficient supply side technologies viz Integrated Gasification Combined Cycle (IGCC) and Pressurized Fluidized Bed Combustion (PFBC) and presents the least cost planning results with these technologies on the NREB system

In **Chapter 4** the results on the NREB system have been obtained with GHG (only CO_2 in the present study) mitigation constraints and their impact on the planning results have been analyzed

Chapter 5 concludes the main findings of the work carried out in this thesis and lists some of the future scope of research work

CHAPTER-2

CONVENTIONAL LEAST COST GENERATION EXPANSION PLANNING

2 1 Introduction

The aim of the energy resource planning is to investigate comprehensively the effective use co ordination and substitution relationship of various primary resources such as coal crude oil natural gas hydro energy nuclear energy etc The aim of the least cost generation expansion planning is to seek the most economical generation expansion scheme achieving a certain reliability level according to the forecast of demand increase in a given period of time The cost factors include the capital investment cost and the power generating cost Capital investment cost denotes the total capital outlay necessary to build a power plant It depends on the depreciation taxes interest rate etc Power generation cost represents the total cost of generating electricity Power generating cost includes the fixed fuel cost variable fuel cost fixed operating and maintenance cost variable operating and maintenance cost Fuel costs play a major role in the least cost generation expansion planning Different types of fuels considered in the present study are coal oil gas and nuclear The coal has been further categorized into six types according to their calorific value cost and different process required for the combustion of the fuel Operation and maintenance (O&M) cost includes all non fuel cost i e it includes direct and indirect cost of labour and supervisory personnel consumable supplies and equipments outside support services moderator and coolant make up nuclear liability insurance etc Fixed operating and maintenance (O&M) cost depends on the size and type of plants but not the load factor Variable O&M cost depends on production i e plant capacity factor In case of the hydro power plants the fuel cost is considered to be zero

In this chapter the least cost generation expansion planning studies have been carried out on Northern Region Electricity Board network Various sensitivity analyses have also been carried out with respect to the change in values of discount rate fuel prices (oil coal and gas) power demand and supply side capital cost The studies have been conducted for the planning horizon of 15 years (year 2003 2017) The Integrated Resource Planning Analysis (IRPA) software supplied by Asian Institute of Technology (AIT) Thailand has been used for the formulation of Mixed Integer Program (MIP) object code and the CPLEX linear optimizer is used for the analysis of the least cost generation expansion planning

2 2 Mathematical Formulation

The formulation of the conventional generation expansion planning is based on the least cost optimization criteria [5] as described below

2 2 1 Objective function

The least cost generation expansion planning minimizes the total cost of candidate power plants and the cost of power generation from existing and candidate power plants over the complete planning horizon

Let the total planning horizon is for T years each year having s seasons each season divided into P blocks each block divided into t vintages J being the total number of candidate power plants and K being the total number of existing power plants

Mathematically the least cost generation expansion plan has objective to

$$\text{Minimize} \quad \sum_{j=1}^{J}\sum_{v=1}^{T}\left(C_{jv}-W_{jv}\right)\times Y_{jv} +$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=1}^{t}\sum_{j=1}^{J}U_{jpstv}\times F_{jpstv}\times N_{st}\times\theta_{pst}+$$

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{v=-V}^{t}\sum_{k=1}^{K}U_{kpstv}\times F_{kpstv}\times N_{st}\times\theta_{pst} \qquad (2.1)$$

Where

C_{jv} Discounted capital cost of candidate power plant j to be commissioned in vintage v

W_{jv} Discounted salvage value of power plant j commissioned in year v after time horizon T

Y_{jv} Number of power plants of type j installed in year v (An integer variable)

YP_{mv} Number of pump storage hydro plants type m installed in year v (An integer variable)

N_{st} Number of days in season s of year t

θ_{pst} Width of block p of chronological load curve of season s of year t

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

F_{jpstv} Cost of per unit power generation from candidate power plant j of vintage v in block p of season s in year t

U_{kpstv} Power generation from plant k of vintage v in block p of season s in year t

F_{kpstv} Cost of per unit power generation from existing or committed power plant k of vintage v in block p of season s in year t

2.2.2 Constraints

The above least cost optimization is subject to the following system constraints

a) Demand constraints

This constraint states that the total power generation in each block of the planning horizon from candidate and existing plants will be more than or equal to the power demand during that period. It can be mathematically written as

$$\sum_{v=1}^{t}\sum_{j=1}^{J} U_{jpstv} \times \left(1 - M_{jpst}\right) + \sum_{v=-V}^{t}\sum_{k=1}^{K} U_{kpstv} \times \left(1 - M_{kpst}\right) \geq Q_{pst} \tag{2.2}$$

for all p s t

Where

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

M_{jpst} Transmission loss for transmitting power from candidate generating station j to load center in block p of season s in year t

U_{kpstv} Power generation from existing plant k of vintage v in block p of season s in year t

M_{kpst} Transmission loss for transmitting power from existing generating station k to load center in block p of season s in year t

b) Reliability constraints

This constraint imposes the condition that the power demand from all the plants (the candidate and the existing plants of all the types) must be greater than or equal to the sum of the power demand by the consumers and the reserve margin

$$\sum_{k=1}^{K}\sum_{v=-V}^{t} B_{kv} \times \left(1 - M_{kp^*st}\right) + \sum_{j=1}^{J}\sum_{v=1}^{t} Y_{jv} \times B_{jv} \times \left(1 - M_{jp^*st}\right) \geq Q_{p^*st}\left(1 + rm\right) \tag{2.3}$$

for all t s

(P^* represents the peak block)

Where

B_{kv} Maximum capacity of existing or committed power plant k of vintage v

M_{kp^*st} Transmission loss for transmitting power from generating station k to load center in block p of season s in year t

Y_{jv} Number of power plants of type j installed in year v (An integer variable)

B_{jv} Maximum capacity of candidate power plant j of vintage v

M_{jp^*st} Transmission loss for transmitting power from candidate generating station j to load center in block p of season s in year t

Q_{p^*st} Power demand in block p of season s in year t

rm Reserve margin

c) **Guarantee condition for energy supply for mixed hydro thermal system**

This constraint states that the energy available from all the plants must be greater than or equal to the energy demand during all time interval and seasons

$$\sum_{k=1}^{K}\sum_{=-V}^{t}\sum_{p=1}^{P} a_{kv} \times B_{kv} \times Y_{kv} \times \theta_{pt} + \sum_{j\,1}^{J}\sum_{=1}^{t}\sum_{p\,1}^{P} a_{jv} \times B_{j} \times Y_{j} \times \theta_{pt} +$$

k ≠hydro j≠hydro

$$\sum_{k-1}^{K}\sum_{=-V}^{t}\sum_{f=1}^{P} \beta_{k} \times U_{kfstv} \times \theta_{pst} + \sum_{j-1}^{J}\sum_{v=1}^{t}\sum_{p=1}^{P} \beta_{j} \times U_{jpt} \times \theta_{pt} \geq \sum_{P=1}^{P} Q_{pt} \times \theta_{jt} \qquad (2\,4)$$

k=hydro j=hydro

for all t s

Where

a_{kv} Availability of existing or committed power plant k of vintage v

B_{kv} Maximum capacity of existing or committed power plant k of vintage v

Y_{kv} Number of power plant of type k installed in year v (an integer variable)

θ_{pst} Width of block p of chronological load curve of season s in year t

a_{jv} Availability of candidate power plant j of vintage v

B_{jv} Maximum capacity of candidate power plant j of vintage v

Y_{jv} Number of power plant of type j installed in year v (An integer variable)

β_{kv} Maximum capacity of existing or committed power plant k of vintage v

U_{kpstv} Power generation form plant k of vintage v in block p of season s in year

β_{jv} Firm factor of hydro plant j of vintage v

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

Q_{pst} Power demand in block p of season s in year t

d) Plant availability constraints

This constraint defines the maximum available generation from each power plant depending on their availability factor

$$U_{jpstv} \leq Y_{jv} \times a_{jv} \times B_{jv}$$

for all j v p s t

and

$$U_{kpstv} \leq a_{kv} \times B_{kv}$$

for all k v p s t (2 5)

Where

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

Y_{jv} Number of power plants of type j installed in year v (An integer variable)

a_{jv} Availability of candidate power plant j of vintage v

B_{jv} Maximum capacity of candidate power plant j of vintage v

U_{kpstv} Power generation from plant k of vintage v in block p of season s in year t

a_{kv} availability of existing or committed power plant k of vintage v

B_{kv} Maximum capacity of existing or committed power plant k of vintage v

e) Annual energy constraints

This constraint defines the maximum energy which can be generated from each plant considering their maintenance period

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{jpstv} \theta_{pst} \times N_{st} \leq (8760 - m_{jv}) \times B_{jv} \times Y_{jv}$$

for all j v t

and

$$\sum_{p=1}^{P}\sum_{s=1}^{S} U_{kpstv} \times \theta_{pst} \times N_{st} \leq (8760 - m_{kv}) \times B_{kv}$$

for all k v t (2 6)

Where

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

θ_{pst} Width of block p of chronological load curve of season s of year t

N_{st} Number of days in season s of year t

m_{jv} Schedule maintenance hours per year of candidate power plant j of vintage v

B_{jv} Maximum capacity of candidate power plant j of vintage v

Y_{jv} Number of power plants of type j installed in year v (An integer variable)

U_{kpstv} Power generation from plant k of vintage v in block p of season s in year t

m_{kv} Schedule maintenance hours per year of existing or committed plant k of vintage v

B_{kv} Maximum capacity of existing or committed power plant k of vintage v

f) Hydro energy availability constraints

This constraint defines the limit on total hydro energy generation available from each hydro plant during each period

$$\sum_{p=1}^{P}\left(U_{jpstv}\times\theta_{pst}\right)\times N_{t}\leq\pi_{jtv}$$

for all j s t v (j=Hydro plants)

and

$$\sum_{p=1}^{P}\left(U_{kptv}\times\theta_{pt}\right)\times N_{t}\leq\pi_{ktv}$$

for all k s t v (k=Hydro plants) (2 7)

Where

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

θ_{pst} Width of block p of chronological load curve of season s of year t

N_{st} Number of days in season s of year t

π_{jstv} Hydro energy available at hydro plant j of vintage v in season s in year t

U_{kpstv} Power generation from plant k of vintage v in block p of season s in year t

π_{kstv} Hydro energy available at hydro plant k of vintage v in season s in year t

g) Maximum potential capacity constraints

This constraint imposes the limit on the number of power plants of any type installed in any year

$$\sum_{=1}^{T} Y_{j} \le \alpha_{j}$$

for all j (2 8)

where

Y_{jv} Number of power plants of type j installed in year v (An integer variable)

α_j Maximum number of units of power plant type j

h) Fuel or resource availability constraints

This constraint imposes the maximum limit on energy generation for each type computed from the availability of fuel resources

$$\sum_{t=1}^{T}\sum_{s=1}^{S}\sum_{p=1}^{P}\sum_{=-V}^{t} Y_{kv} \times U_{kj\,stv} \times \theta_{pst} \times N_{t} + \sum_{t=1}^{T}\sum_{=1}^{S}\sum_{p=1}^{P}\sum_{=1}^{t} Y_{j} \times U_{jj\;tv} \times \theta_{pst} \times N_{st} \le X_{j\max}$$

for all k j k and j are some type of plants (2 9)

Where

Y_{kv} Number of power plants of type k installed in year v (An integer variable)

U_{kpstv} Power generation from plant k of vintage v in block p of season s in year t

θ_{pst} Width of block p of chronological load curve of season s of year t

N_{st} Number of days in season s of year t

Y_{jv} Number of power plants of type j installed in year v (An integer variable)

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

$X_{j\max}$ Maximum energy resource available for plant type j (computed based on the maximum fuel resource availability)

In India Northern Electricity Board is one of the regional electricity boards (REBs) The system description and data of Northern Regional Electricity Board for the present study are given below

2 3 NREB System Description

2 3 1 Electricity demand projection

The projected value of energy peak power demand energy consumption in different sectors of the Northern Regional Electricity Board (NREB) are given below

2 3 1 1 Review of historical data

The percentage of utilization of electiical energy in different sectors during 1996 1997 [22] were as given in Table 2 1 The similar pattern is also continuing at present

Table 2 1 Utilization of electrical energy in different sectors

Sector	Percentage (%)
Domestic Consumption	19 72
Commercial and Misc	7 89
Irrigation	29 99
Industry	37 18
Others	5 22
Total	100 00

The total energy consumption in NREB during the periods 1990 1991 to 2001 2002 (actual/estimated) are given in Table 2 2 [22]

Table 2 2 Energy consumption in northern region from 1990 2002

Year	MU (million kWH)
1990 1991	54986
1991 1992	60639
1992 1993	65313
1993 1994	75247
1994 1995	81480
1995 1996	87986
1996 1997	95099
1997 1998	102516
1998 1999	110293
1999 2000	118628
2000 2001	127434
2001 2002	136988

2 3 1 2 Energy and electricity demand projection

Central Electricity Authority (CEA) New Delhi is responsible for the electricity planning in the country Central Electricity Authority New Delhi is the main authority for generation expansion planning for the five regions in India CEA New Delhi uses Electricity Generation Expansion Analysis System (EGEAS) and Integrated System Planning Model (ISPLAN) two powerful softwares for the planning studies

As per the projections made by the 15th Electric Power Survey (EPS) [21] the electrical energy and peak power demand which stood at 3 89 721MU and 60 981MW during 1995 1996 are going to increase as given in Table 2 3 For our study the forecast was required up to year 2017 for which the data was not available So peak demand up to 2017 has been extrapolated by taking average percentage growth of 6 42% Demand in between the years i e between 2001 02 & 2006 07 2006 07 & 2011 12 have been calculated through interpolation of EPS data The interpolation has been done from the previous years datas The peak demand and power generated from

the year 1992 to 1997 is given in the figure 5 of Annex E All these data are shown in Annex A in the IRPA format

Table 2 3 Energy and power projection for Northern Regional Electricity Board

Forecast [1]	By end of 9th plan (2001 2002)	By end of 10th plan (2006 2007)	By end of 11th plan (2011 2012)
Peak Demand (MW)	31735	44009	60077
Energy (MU)	181649	254161	350165

The above projection includes all industrial and non industrial loads with a demand of 1MW and above and also includes the agricultural loads

The projected power consumption in percentage for different sectors or categories for the periods [2000 2001] and [2001 2002] are given in Table 2 4 [22]

Table 2 4 Power consumption in different sectors in percentage for NREB

Sl No	Sectors/Categories	All figures are in percentage	
		Year 2000 2001	2001 2002
1	Domestic	22 67	23 52
2	Commercial and Miscellaneous	6 98	7 03
3	Public lighting	0 79	0 798
4	Public water work	2 25	2 28
5	Irrigation and Dewatering	24 70	24 10
6	Industrial	39 30	39 00
7	Railway	2 37	2 36
8	Bulk supply and Non Industrial consumers	0 90	0 90

2 3 2 NREB system

The NREB system has 160 thermal power plants and 230 hydro power plants All the data required for some of the case studies are given in Annex A to D Pump storage power plants are not considered as these have negligible contribution towards total generation In IRPA chronological load curve is required Chronological load curve is given in the fifure 6 of Annex E For this purpose normalized load is needed which is shown in Annex A For normalised load peak load is required for each year of the planning period The projected peak load is shown in the figure 4 of Annex E Two seasons are taken in one year and 20 blocks considered in each season Season 1 consisting of July August and September and season 2 consisting of rest of the months Season 1 is of total 92 days and season 2 of total 273 days Only three types of candidate thermal power plants and one type of candidate hydro power plants are taken for least cost generation expansion planning without the efficient technology Load factor is calculated by projected energy and projected peak demand which is shown in Annex A and section 2 3 4 Projected load factor curve for whole planning period is shown in the figure 3 of Annex E Reserve margin is taken as 5% for all the years which is the norm followed by CEA Total ten types of fuels were considered namely coal 1 coal 2 coal 3 coal 4 coal 5 coal 6 gas nuclear lignite oil Costs for various types of coals are different The costs for all the fuels are shown in Annex A Cost multiplication factor for year 2003 is taken as 1 2 and for the rest of the years it is taken as 1 05 Only four types of plants are taken namely the conventional coal combined cycle gas turbine unit (TU) nuclear and lignite which are sufficient to include all the plant types for the least cost generation expansion planning There are no external suppliers for the NREB Similarly there is no group data in the case study Discount factor is taken as 10% the base year as 1998 and starting year for the study is 2003 Study period is assumed to be for 15 years i e up to 2017

2 3 2 1 Existing power plant's data

Under the control of Northern Regional Electricity Board (NREB) there are total 160 thermal power plants and 230 hydro plants as given in Annex A

A) Thermal power plants

All existing thermal power plants are shown in Annex A Fuel consumption data is provided by CEA from the available plant monthly report Calorific value of different types of fuels is taken from the available data SO_2 and CO_2 emission factors were calculated from the formula adopted by CEA and also given in section 2 3 3 2 NO_x emission factor was computed from the Table 1 15 of IPCC document [28] and with the help of the formula given in the section 2 3 3 2 Minimum operating capacity of all the plants is taken as 30% of the installed capacity Heat rate is taken on the basis of the available plant monthly report Operating cost is taken as 1% of total capital cost or 40% of fixed operating and maintenance (O&M) cost The fixed operating and maintenance (O & M) cost is taken as 2 5% of total capital cost for all types of thermal plants except the diesel plants which is considered as 4% Transmission loss rate is taken as 4% for all the plants Annual maintenance hour for coal based plants and nuclear plants is taken as 10% while for the gas based plants and oil based plants it is taken as 15% according to the CEA norms for generation planning in India Fuel types and plant types are shown in Annex A

B) Hydro power plants

All the existing hydro power plants are shown in Annex A There are total 230 plants Availability is taken according to the CEA norms Operating cost for hydro plants is assumed to be zero Transmission loss rate is taken as 4% for all the plants Fixed operation and maintenance (O & M) cost is taken as 1 5% of the total capital cost Available energy in season one (July August and September) and season two (rest of the months) is shown in Annex A

2 3 2 2 Candidate power plants

Total three types of candidate thermal plants were considered for the study of least cost generation expansion planning Only one type of candidate hydro power plant was considered Details of plants are given in Annex A

The thiee types of candidate thermal plants considered are coal 500MW CCGT 250MW and nuclear 500MW Fuel consumption rate and calorific values of these plants are taken as the average of the fuel consumption and the calorific values of all the existing similar plants in the NREB system Annual allowable maximum unit is taken as 150 foi coal 500MW 75 foi CCGT 250MW and 4 for nuclear 500MW Availability for nuclear is taken as 0 58 and for coal 500MW as 0 71 Tiansmission loss rate is taken as 4% Maximum possible number of incremental units is taken as 150 for the coal 500MW & 75 for CCGT 250MW and 4 for nuclear 500MW for the year 2006 2017 These are given in Annex A The depreciable and non depreciable cost for candidate thermal power plants have been taken as 90% and 10% of the total installation cost of the power plant respectively

For candidate hydro power plants only one type of plant is considered which is of 250 MW having 35% efficiency Since hydro plants take much time to be built the earliest available year is taken as 2005 Maximum number of units is taken as 5 The hydro plants were taken in each two years interval up to 2015 Availability is taken as 90% Operating cost is considered to be zero and transmission loss rate as 4% Available energy in each season is taken according to the existing hydro power plant of 250 MW capacity For the candidate hydro power plant only the total cost is taken rather than the depreciable and non depreciable cost taken in case of the existing thermal power plants

2 3 3 Calculation of emission constraints and heat rate

2 3 3 1 Evaluation of heat rate at full load

The aveiage inciemental heat rate (a) can be calculated as

$$a = \frac{(H_F - H_O)}{(L_F - L_O)} = \frac{(HR_F \times L_F - HR_O \times L_O)}{(L_F - L_O)}$$

Rearranging the above equation provides the following expression for the heat rate at full load (HR_F)

$$HR_r = \frac{(HR_O \times L_O + a(L_F - L_O))}{L_F} \tag{2 10}$$

Where

L_F H_F = Full load in kW and corresponding heat rate in kcal/h

L_O H_O = Minimum allowable load in kW and corresponding heat rate in kcal/h

2 3 3 2 Estimation of pollution level

Various types of air pollution factors can be computed as given below

CO_2 emission factor [21]

$$ef_{co_2}\left[\frac{Kg}{Kwh}\right] = \left(44/12\right) \times 10 \times C \quad \times P$$

SO_2 emission factor [21]

$$ef_{so_2}\left[\frac{Kg}{Kwh}\right] = 2 \times 10 \times C_{con} \times P_{sul}$$

NO_x emission factor is referred from [IPCC 1996 Table 1 15 21]

$$ef_{no}\left[\frac{Kg}{Kwh}\right] = \frac{NO_x \times 0\ 4187 \times H\ R}{10^5}$$

Where

ef Emission factor (Kg/Kwh)

C_{con} Specific coal consumption in Kg/Kwh

P_{car} Percentage of carbon in coal

P_{sul} Percentage of sulphur in coal

Ef_{Nox} Emission factor (Kg/Mwh)

H R Heat rate in Kcal/Kwh

NO_x The NO_x emission expressed in Kg/TJ

The value of NO_x is calculated for various types of plants using the figure given in the table of Annex E

2 3 4 Calculation of load factor and efficiency of plants

The load factor is computed from the following formula

Load Factor = Energy / (Peak Demand × Hours in one year)

Plant efficiency (η) has been calculated from the heat rates as following

$$\eta = \frac{860}{H\,R} \times 100\%$$

Where

H R Heat rate of the plant at full load in kcal/kWh

A 100% efficient plant gives 1kwh out put for 860kcal of input heat energy

The IRPA package considers cost figure in the US Dollars For this purpose a conversion factor of one US Dollar equal to 45 Indian Rupees has been considered

2 4 Case Studies

With the help of IRPA software of AIT Thailand which formulate the MIP object code from the datas given and the CPLEX optimizer which optimizes the object code various case studies were carried out on the NREB system For the case studies all the datas required were taken as given in the Annex A Emission constraint and DSM constraints were not considered in this case The results of the least cost generation expansion planning are given below

2 4 1 Least cost generation expansion planning Base case

For the least cost generation expansion planning of NREB system the datas were first prepared in the IRPA format The IRPA was run for the base case henceforth called as Business As Usual (BAU) case which provided the object code This was then fed to the CPLEX software to solve the optimization problem The results with respect to the selection of units during the planning horizon 2003 to 2017 along with

various cost components are given in Table 2 5 A summary of fixed O&M cost fuel and variable cost and total as well as various types of emissions for each of the planning years as well as for the complete planning period is given in Tables 2 5 & 2 6

It is worth noting that in the BAU case all the candidate coal based thermal plants and hydro plants have been selected for the future expansion since the costs of these power plants were relatively less

TABLE 2 5 Plant selection by least cost generation expansion planning

GENERATION EXPANSION PLAN

Year	Plant Selection		Discounted cap cost (k$)	Salvage value (k$)	Net capital Cost (k$)	Nominal cost (k$)
2003	COAL 500	(39 x 500 MW)	12107965 80	1594202 91	10513762 89	19500000 00
2003	CCGT-250	(2 x 250 MW)	241538 39	26607 21	214931 19	389000 00
2004	HYDRO-250 35%	(5 x 250 MW)	705592 41	133779 27	571813 15	1250000 00
2005	COAL 500	(5 x 500 MW)	1282895 30	226681 53	1056213 76	2500000 00
2006	COAL 500	(3 x 500 MW)	699761 07	142697 88	557063 19	1500000 00
2006	HYDRO-250 35%	(5 x 250 MW)	583134 23	141211 45	441922 78	1250000 00
2007	COAL 500	(7 x 500 MW)	1484341 66	348569 31	1135772 36	3500000 00
2008	COAL 500	(4 x 500 MW)	771086 58	208101 08	562985 50	2000000 00
2008	NUCLEAR-500	(2 x 500 MW)	513543 66	138535 86	375007 80	1332000 00
2008	HYDRO-250 35%	(5 x 250 MW)	481929 11	148643 63	333285 48	1250000 00
2009	COAL 500	(9 x 500 MW)	1577222 55	488294 32	1088928 23	4500000 00
2010	COAL 500	(7 x 500 MW)	1115207 86	395392 05	719815 81	3500000 00
2010	HYDRO-250 35%	(5 x 250 MW)	398288 52	156075 81	242212 71	1250000 00
2011	COAL 500	(9 x 500 MW)	1303489 71	528428 10	775061 61	4500000 00
2012	COAL 500	(9 x 500 MW)	1184990 64	548494 99	636495 66	4500000 00
2012	HYDRO-250 35%	(5 x 250 MW)	329164 07	163507 99	165656 08	1250000 00
2013	COAL 500	(11 x 500 MW)	1316656 27	694908 96	621747 31	5500000 00
2014	COAL 500	(10 x 500 MW)	1088145 68	654031 96	434113 72	5000000 00
2014	HYDRO-250 35%	(5 x 250 MW)	272036 42	170940 17	101096 25	1250000 00
2015	COAL 500	(12 x 500 MW)	1187068 01	811594 21	375473 80	6000000 00
2016	COAL 500	(12 x 500 MW)	1079152 74	838350 06	240802 68	6000000 00
2016	CCGT-250	(1 x 250 MW)	34982 53	26830 17	8152 36	194500 00
2017	COAL 500	(13 x 500 MW)	1062801 94	937198 07	125603 87	6500000 00
2017	NUCLEAR-500	(1 x 500 MW)	108896 32	96023 78	12872 54	666000 00
Total capital cost					21310790 71	85081500 00

Table 2 6 Summary of the total cost and emissions levels

ANNUAL DISCRIPTION

Year	Capital(k$)	Fix O&M (k$)	Fuel & Var (k$)	Annual Total	CO2(Gg)	SO2(Mg)	NOX(Mg)
2003	10728694 1(73 %)	758105 8(5 %)	3185012 3(22 %)	14671812 2	206283 3	1213982 9	557482 2
2004	571813 1(15 %)	689187 1(18 %)	2649479 8(68 %)	3910480 0	215798 9	1290043 5	581079 4
2005	1056213 8(25 %)	655890 4(15 %)	2561060 6(60 %)	4273164 7	232793 0	1392024 4	622857 0
2006	998986 0(25 %)	612276 7(15 %)	2414437 0(60 %)	4025699 6	244024 9	1460360 7	650590 6
2007	1135772 4(28 %)	590581 5(15 %)	2345280 9(58 %)	4071634 8	263612 3	1577698 8	697971 5
2008	1271278 8(31 %)	566447 4(14 %)	2259212 6(55 %)	4096938 8	276253 7	1646595 0	729692 4
2009	1088928 2(28 %)	551043 9(14 %)	2207641 3(57 %)	3847613 4	301059 9	1796378 4	789297 6
2010	962028 5(26 %)	526468 4(14 %)	2142535 8(59 %)	3631032 8	321724 1	1914494 8	839942 4
2011	775061 6(23 %)	508435 6(15 %)	2110933 6(62 %)	3394430 7	348810 6	2071003 5	907200 8
2012	802151 7(24 %)	489330 4(15 %)	2035573 3(61 %)	3327055 4	373507 4	2217239 1	966128 9
2013	621747 3(20 %)	474975 0(15 %)	1991194 3(64 %)	3087916 6	404737 9	2401948 0	1042003 5
2014	535210 0(18 %)	456695 6(16 %)	1928642 9(66 %)	2920548 5	433285 1	2569978 6	1111444 1
2015	375473 8(14 %)	442341 6(16 %)	1888787 8(70 %)	2706603 2	468023 3	2771964 7	1196217 8
2016	248955 0(10 %)	427682 3(17 %)	1854578 2(73 %)	2531215 5	503985 7	2974841 6	1284636 3
2017	138476 4(6 %)	415647 8(18 %)	1806919 1(77 %)	2361043 3	541294 7	3193425 2	1375498 3
Total	21310791 7(34 %)	8165109 5(13 %)	33381289 5(53 %)	62857189 6	5135194 8	30491979 3	13352042 9

2 4 2 Sensitivity analyses

In order to study the impact of change in the values of various assumed parameters on the least cost planning results sensitivity analyses were carried out The results with respect to different parameter variables are provided below

2 4 2 1 Discount rate

The discount rate was varied by +50% and –50% of the base case value and the summary of results obtained are given in Table 2 7 It can be observed that in both the cases all coal based thermal plants and hydro plants were selected With reduction in the discount rate total cost has considerably increased where as there is a marginal change in the emission level

Table 2 7 Results with change in discount rate values

Discount Rate in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	Total cost in G$	CO emission in TKg	SO_2 emission in GKg	NO emission in GKg
+50%	150	4	2	30	41 74	5 13	30 45	13 36
50%	150	2	4	30	98 41	5 11	30 54	13 29

2 4 2 2 Fuel prices

Fuel prices were changed by following percentage

- ±10% in the coal price
- ±25% and ±50% in the oil price
- ±25% and only +50% in the gas price

The summary of the results is given in Table 2 8 It can be observed that the total CO_2 emission for each of the above cases is almost insensitive to the variation in

coal and oil prices However it is most sensitive when gas price is changed CO_2 (also NO_x and SO_2) emission increases with increase in gas price

Table 2 8 Results on change with values of fuels cost

Type of fuels	Change in cost as % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
Coal	+10	150	2	4	30	65 46	5 11	30 35	13 30
Coal	10	150	3	3	30	60 23	5 14	30 55	13 37
Oil	+25	150	3	3	30	62 90	5 13	30 51	13 35
Oil	25	150	3	3	30	62 81	5 13	30 47	13 34
Oil	+50	150	3	3	30	62 94	5 13	30 48	13 35
Oil	50	150	4	2	30	62 76	5 13	30 53	13 36
Gas	+25	150	2	4	30	63 91	5 19	31 12	13 46
Gas	25	150	4	2	30	61 63	5 12	30 36	13 33
Gas	+50	150	2	4	30	64 54	5 22	31 49	13 51

2 4 2 3 Power demand

The power demand was changed by +10% and –20% of the base case value The results of plants selected total cost and various emissions are given in the Table 2 9 The change in total cost and emission levels follow the variation in power demand

Table 2 9 Results with change in values of power demand

% change in power demand fromBAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	Total Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+10%	150	44	4	30	71 58	5 74	33 83	14 86
20%	106	2	2	30	45 74	3 82	22 82	10 15

2 4 2 4 Supply side capital cost

Supply side capital cost was changed by ±20% and –40% only The results are given in the Table 2 10 The change in the capital cost has affected mainly the total cost figures It has resulted in only a marginal change in the emission levels

Table 2 10 Results with change in supply side capital costs

Change in the capital as % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	Total Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+20%	150	4	2	30	67 11	5 13	30 44	13 35
20%	150	2	4	30	58 59	5 12	30 45	13 32
40%	150	2	4	30	54 26	5 12	30 60	13 29

2 5 Conclusion

In this chapter least cost generation expansion planning had been carried out on the NREB system The datas for this case study was collected from the CEA New Delhi For various studies IRPA package along with CPLEX optimizer and MIP code formulator has been used Various sensitivity analyses were carried out with the change in different parameters value The results obtained for the different cases provide the following main conclusions

- In the BAU case all the candidate hydro and coal plants were selected due to their relatively lower overall cost
- With the variation of the discount rate the selection of coal and hydro plants remained same With increase in discount rate more CCGT plants are selected while with the decrease in the discount rate more nuclear plants get selected The total cost increases considerable with the reduction in the discount rate The emission levels of CO_2 SO_2 and NO_x remain almost same as in the BAU case

- The change in fuel prices affect the total cost in case of price variation of coal and gas where as it is almost same in case of variation of the oil price The CO_2 emission is lowest (5 11Tkg) when coal price is increased by +10% and highest (5 22Tkg) when gas price is increased by +50% This pattern also applies to SO_2 and NO_x emissions In this sensitivity analysis it was also observed that relatively more number of CCGT plants were selected when gas and oil prices are reduced and more number of nuclear plants get selected when coal and gas prices are increased Number of coal based plants and hydro plants remain same as in the BAU case
- Increase in power demand causes large number of CCGT plants to be selected Reduction in power demand reduced the number of all types of thermal plants The variation in the cost and emission follow the load variation
- Supply side capital cost variation changes the total cost of the plants where as it has practically no impact on the three types of emissions

CHAPTER-3

LEAST COST GENERATION EXPANSION PLANNING WITH EFFICIENT TECHNOLOGIES

3 1 Introduction

In the least cost generation expansion planning as observed in the previous chapter mostly coal based candidate plants are selected This results in increased emission levels including the CO_2 emission Greenhouse Gas (GHG) emissions can be mitigated by considering efficient supply side options These options are listed below

The supply side options include the follows

- Fuel switching (i e from high carbon to low /non- carbon fuels) [41]
- Cleaner thermal power generation technologies (e g Combined Cycle Pressurized Fluidized Bed Combustion (PFBC) Atmospheric Fluidized Bed Combustion (AFBC) Integrated Gasification Combined Cycle (IGCC) power plant)
- Power generation from renewable sources (e g hydro wind solar geothermal sea wave ocean thermal tidal etc)
- Co firing of biomass with coal in power plants [6]
- Retrofitting of older power plants i e renovation and modernization (R&M) of old plants
- Transmission and distribution loss reduction
- Pre combustion technologies
- Post combustion technologies (e g Flue Gas Desulphurization)

The demand side management includes

- Replacement electrical appliances or gadgets with high efficient technologies
- Replacement of old lamps by energy efficient lamps and energy efficient tubes For example incandescent lamps can be replaced by compact fluorescent lamps
- Use of more energy efficient air conditioners
- Use of energy efficient motors particularly in agricultural sectors

However in this chapter only two supply side technologies have been considered namely Integrated Gasification Combined Cycle (IGCC) and Pressurized Fluidized Bed Combustion (PFBC) technologies to reduce the emission levels The base case study along with these new types of plants as candidate plants and also various sensitivity analyses have been carried out on the NREB system using IRPA package

3 2 Clean Technologies

The two types of supply side clean technologies viz PFBC and IGCC combined in the present study are briefly described below

3 2 1 Pressurized fluidized bed combustion

By using Pressurized Fluidized Bed Combustion (PFBC) technology the plant efficiency can be improved upto about 45% PFBC is clean coal technology associated with coal gasification Main furnace operates under pressure In this technology ash sulphur and impurities are removed at the combustion stage of fuel burnt to control different emissions The lime is added in the coal at the time of combustion of coal so that the energy required for burning the sulphur can be saved The lime reacts with the sulphur forms the compound and comes out as waste matter The SO_2 emission will be less in this case NO_x is controlled by lowering temperature of combustion water spray or using special burner Fluidized bed combustion can burn coal efficiently at a temperature low enough to that of the powder coal burning temperature As the NO_x

emission depends on the combustion temperature its level will decrease Due to the gasification of the coal the CO_2 emission will also be less

3 2 2 Integrated gasification combined cycle

IGCC is a promising power generation option which can be applied to a great variety of solid or liquid feedstock It offers some unique options such as co production of electric power bricks and chemicals simultaneously It is the technology employed to control emission at the combustion stage of the fuel By using this one can reduce pollutant s emission level and water consumption amount besides improving the overall efficiency of the power plants which may be more than 45% In such plants the coal is gassified to lower degree before it goes to the combustion Before going to combustion and at the time of gassification the lime is added to the coal to take out sulphur before burning of the gasified coal Reduction in sulphur compound can be achieved by clean up at 350 400 °C by absorption on supported iron oxides Coal gasification provides a potential option for reducing CO_2 emission of coal fired plants As the burning temperature is low enough so the NO_x emission is low The high ash (30% 40%) content of Indian coal requires IGCC technology for the power generation

3 3 Case Studies and Results

The datas required for various case studies for generation expansion planning with efficient technologies are same as that for the least cost generation expansion planning in chapter 2 Additional data required for the IGCC and PFBC plants are given in the Annex A The methodology for this case is same as for the least cost generation expansion planning given in chapter 2 section 2 2 The IRPA package along with the CPLEX has been used for this study

3 3 1 Least cost generation expansion planning

For the least cost generation expansion planning of NREB system the data was first prepared in the IRPA format The IRPA was run for the base case henceforth

called as Business As Usual (BAU 1) case The results with respect to the selection of units during the planning horizon from 2003 to 2017 along with various cost components are given in Table 3 1 A summary of fixed O&M cost fuel and variable cost and total as well as various types of emissions for each of the planning years and also for the complete planning period are given in Tables 3 1 and 3 2

It is worth noting that in the BAU case all the candidate hydro plants IGCC and PFBC plants were selected for the future expansion case study The coal plant selection was reduced due to its higher cost than the efficient technologies It was observed by comparing with the BAU case results without efficient technologies in chapter 2 that the total cost reduces by approximately 1% Emission levels of CO_2 SO_2 and NO_x reduces by approximately 4% 12% and 9% respectively For both the BAU and BAU 1 case selection of CCGT and nuclear plants remain same

Table 3 1 Plant selection by least cost generation expansion planning with efficient technologies

GENERATION EXPANSION PLAN

Year	Plant Selection		Discounted cap cost (k$)	Salvage value (k$)	Net capital Cost (k$)	Nominal cost (k$)
2003	COAL 500	(39 x 500 MW)	12107965 80	1594202 91	10513762 89	19500000 00
2003	CCGT-250	(2 x 250 MW)	241538 39	26607 21	214931 19	389000 00
2004	HYDRO-250 35%	(5 x 250 MW)	705592 41	133779 27	571813 15	1250000 00
2005	PFBC 500	(3 x 450 MW)	812457 59	143552 58	668905 01	1583250 00
2005	IGCC 500	(2 x 400 MW)	570169 99	100745 70	469424 29	1111100 00
2006	PFBC 500	(3 x 450 MW)	738597 81	150613 16	587984 65	1583250 00
2006	HYDRO-250 35%	(5 x 250 MW)	583134 23	141211 45	441922 78	1250000 00
2007	PFBC 500	(4 x 450 MW)	895270 07	210231 64	685038 43	2111000 00
2007	IGCC 500	(2 x 400 MW)	471214 86	110655 27	360559 59	1111100 00
2008	NUCLEAR-500	(2 x 500 MW)	513543 66	138535 86	375007 80	1332000 00
2008	IGCC 500	(5 x 400 MW)	1070942 87	289025 15	781917 72	2777750 00
2008	HYDRO-250 35%	(5 x 250 MW)	481929 11	148643 63	333285 48	1250000 00
2009	COAL 500	(7 x 500 MW)	1226728 65	379784 47	846944 18	3500000 00
2009	IGCC 500	(1 x 400 MW)	194716 89	60282 42	134434 46	555550 00
2010	COAL 500	(8 x 500 MW)	1274523 27	451876 63	822646 64	4000000 00
2010	HYDRO-250 35%	(5 x 250 MW)	398288 52	156075 81	242212 71	1250000 00
2011	COAL 500	(9 x 500 MW)	1303489 71	528428 10	775061 61	4500000 00
2012	COAL 500	(9 x 500 MW)	1184990 64	548494 99	636495 66	4500000 00
2012	HYDRO-250 35%	(5 x 250 MW)	329164 07	163507 99	165656 08	1250000 00
2013	COAL 500	(10 x 500 MW)	1196960 25	631735 42	565224 83	5000000 00
2014	COAL 500	(10 x 500 MW)	1088145 68	654031 96	434113 72	5000000 00
2014	HYDRO-250 35%	(5 x 250 MW)	272036 42	170940 17	101096 25	1250000 00
2015	COAL 500	(12 x 500 MW)	1187068 01	811594 21	375473 80	6000000 00
2016	COAL 500	(13 x 500 MW)	1169082 13	908212 57	260869 57	6500000 00
2017	COAL 500	(14 x 500 MW)	1144555 94	1009290 23	135265 70	7000000 00
Total capital cost					21500048 19	85554000 00

Table 3 2 Summary of the total cost and emissions levels with efficient technologies

ANNUAL DISCRIPTION

Year	Capital (k$)	Fix O&M (k$)	Fuel & Var (k$)	Annual Total	CO_2 (Gg)	SO_2 (Mg)	NOX (Mg)
2003	10728694 1 (73 %)	758105 8 (5 %)	3185012 3 (22 %)	14671812 2	206283 3	1213982 9	557482 2
2004	571813 1 (15 %)	689187 1 (18 %)	2649479 8 (68 %)	3910480 0	215798 9	1290043 5	581079 4
2005	1138329 3 (26 %)	654868 7 (15 %)	2527404 3 (58 %)	4320602 4	229365 5	1311342 6	595792 5
2006	1029907 4 (26 %)	611187 8 (15 %)	2363539 9 (59 %)	4004635 1	239827 4	1331271 4	606872 9
2007	1045598 0 (27 %)	583846 4 (15 %)	2283994 5 (58 %)	3913439 0	254383 3	1336080 1	619242 2
2008	1490211 0 (35 %)	563147 8 (13 %)	2164846 1 (51 %)	4218204 9	261600 0	1339102 4	626778 3
2009	981378 6 (27 %)	543745 4 (15 %)	2133994 5 (58 %)	3659118 5	284015 0	1459268 5	680219 7
2010	1064859 4 (29 %)	523479 0 (14 %)	2061155 6 (56 %)	3649494 0	305851 5	1591745 0	732394 7
2011	775061 6 (23 %)	505717 9 (15 %)	2033337 2 (61 %)	3314116 7	332474 1	1743647 3	797682 8
2012	802151 7 (25 %)	486859 8 (15 %)	1968316 9 (60 %)	3257328 5	357634 6	1894489 0	858581 5
2013	565224 8 (19 %)	469990 0 (16 %)	1941898 8 (65 %)	2977113 7	387893 6	2066740 0	933835 3
2014	535210 0 (19 %)	452163 8 (16 %)	1882808 7 (66 %)	2870182 4	416105 0	2231782 2	1001658 5
2015	375473 8 (14 %)	438221 8 (16 %)	1848216 8 (69 %)	2661912 4	451190 0	2436908 6	1088070 0
2016	260869 6 (10 %)	425135 7 (17 %)	1808833 8 (73 %)	2494839 0	488407 2	2654488 1	1178658 6
2017	135265 7 (6 %)	412678 0 (18 %)	1768097 5 (76 %)	2316041 1	528007 9	2887281 8	1274104 5
Total	21500048 1 (35 %)	8118335 0 (13 %)	32620937 7 (52 %)	62239319 9	4958837 4	26788173 4	12132453 1

3 3 2 Sensitivity analyses

In order to study the impact of change in the values of various assumed parameters on the least cost planning results (i e BAU 1) the sensitivity analyses were carried out The results with respect to different parameter variables are given

3 3 2 1 Discount rate

The discount rate was varied by +50% and –50% of the base case value and the summary of results obtained are given in Table 3 3 With +50% variation in discount rate the optimization results did not converge It can be observed that in the case of –50% variation also all coal based thermal plants and hydro plants are selected With reduction in the discount rate total cost has considerably increased where as there is a marginal change in the emission level

Table 3 3 Results with change in discount rate

Discount Rate in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
50%	130	2	4	30	10	10	97 08	4 93	26 60	11 97

3 3 2 2 Fuel prices

Fuel prices were changed by given percentage

A) ±10% in the coal price

B) ±25% and ±50% in the oil price

C) ±25% and only +50% in the gas price

The summary of results are given in Table 3 4 Similar to the results reported in chapter 2 the CO_2 emission level changes only in case of change in the gas price and remains almost same with the variation in the oil and coal price

Table3 4 Results with change in values of fuels cost

Type of fuels	Change in cost on % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO emission in TKg	SO emission in GKg	NO emission in GKg
Coal	+10	131	2	2	30	10	10	64 76	4 95	26 73	12 12
Coal	10	131	2	2	30	10	10	59 69	4 96	26 83	12 15
Oil	+25	131	2	2	30	10	10	62 28	4 95	26 78	12 13
Oil	25	131	2	2	30	10	10	62 19	4 95	26 78	12 13
Oil	+50	131	2	2	30	10	10	62 32	4 95	26 78	12 13
Oil	50	131	2	2	30	10	10	62 14	4 96	26 82	12 13
Gas	+25	131	2	2	30	10	10	63 29	5 0	27 18	12 17
Gas	25	131	2	2	30	10	10	61 03	4 95	26 72	12 11
Gas	+50	136	2	2	30	10	10	63 92	5 05	27 88	12 30

3 3 2 3 Power demand

The power demand was changed by +10% and –20% of the base case value The result of plants selected total cost and various emissions are given in the Table 3 5 With reduction in load the number of conventional thermal plants drastically reduced Variation of cost and emission follows the load change

Table 3 5 Results with change in power demand

% change in power demand from BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+10%	150	6	4	30	10	10	70 81	5 61	30 51	13 69
20%	85	2	2	30	10	10	45 22	3 66	19 43	9 03

3 3 2 4 Supply side capital cost

Supply side capital cost was changed by ±20% and only –40% for this case study The results are given in the Table 3 6 With change in the supply side capital cost the total cost figure varies considerably However it marginally changes the plant selection and emission levels

Table 3 6 Results with change in supply side capital costs

Change in the capital cost as % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+20%	131	2	2	30	10	10	66 53	4 95	26 78	12 13
20%	131	2	2	30	10	10	57 92	4 96	26 78	12 11
40%	130	2	4	30	10	10	53 53	4 93	26 67	11 99

3 3 2 5 Generation efficiency of new power plant

In this case the change in efficiency of the PFBC and IGCC type plants were considered The plants efficiency has been changed by +2% and +5% and then the results are given in the Table 3 7 There is practically no change in the planning result

Table 3 7 Results with change in generation efficiency of efficient plants

Change in generation efficiency	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+2%	131	2	2	30	10	10	62 18	4 95	26 78	12 13
+5%%	131	2	2	30	10	10	62 10	4 95	26 78	12 13

3 4 Conclusion

In this chapter the least cost generation expansion planning analyses with two types of efficient technologies i e IGCC and PFBC were carried out on NREB system The results of the base case study (BAU 1) and different sensitivity analyses provide the following main conclusions on

- With the inclusion of IGCC and PFBC candidate plants in the least cost generation expansion planning the total cost compared to the BAU case in chapter 2 reduces by 15 total emission CO_2 SO_2 and NO_x reduces by 3% a2% and 9% respectively
- The number of candidate plants IGCC and PFBC selected remained constant irrespective of the variation of the parameters in the sensitivity analyses
- Reduction in the discount rate increases the total cost of generation drastically
- The CO_2 emission level is sensitive to only change in the gas price and remain almost same with change in oil and coal prices
- Number of coal based nuclear and CCGT plants selected reduces considerably with decrease in power demand
- Slightly more number of nuclear power plants were selected with the 40% decrease in supply side capital cost Increase in supply side cost increases the total cost but has practically no impact on emission levels
- Variation of efficiency of PFBC and IGCC plants has very little impact on the planning results

CHAPTER-4

GENERATION EXPANSION PLANNING CONSIDERING GHG MITIGATION CONSTRAINT

4 1 Introduction

In India the electricity generation is predominantly from thermal power plants In fact more than 70%of the total power generation is from thermal plants in most of the Asian countries [50] Coal is the dominant fuel used for power generation in India due to sufficient availability of non coking coal in the country itself The use of coal for power generation causes increase in the environmental pollution The power sector is the major contributor of CO_2 which is one of the greenhouse gases For example the share of power sector in total carbon dioxide emission was estimated to be 45% in India [22] Excessive emission of greenhouse gases such as CO_2 causes global environmental problem such as global worming Since this affects almost all the countries most of the developed and developing countries are actively participating in bringing down the emission level of GHG gases [34]

In this chapter the least cost generation expansion planning expansion methodology has been modified to restrict the GHG emissions Only limits on carbon dioxide (CO_2) has been considered in the present study In the previous two chapters the analyses were carried out with the least cost generation expansion planning without any constraint on pollution level Similar to chapter 3 the two efficient technologies for thermal power plants are also considered in this chapter viz PFBC (Pressurized Fluidized Bed Combustion) and IGCC (Integrated Gasification Combined Cycle) plants The mitigation target of GHG by 5% and 10% from the base case (BAU in chapter 2) has been considered The sensitivity analyses have been carried out with

respect to change in the values of various parameters such as the discount rate fuel prices (coal oil gas) power demand supply side capital cost and change in generation efficiency of IGCC and PFBC type power plants The Integrated Resource Planning Analysis (IRPA) software supplied by Asian Institute of Technology (AIT) Thailand has been used for the present work also All the studies have been carried out on the Northern Regional Electricity Board (NREB) system of India

4 2 Methodology

The mathematical formulation of the problem in this chapter is exactly same as the least cost generation expansion planning given in the chapter 2 section 2 2 except for the additional constraints on the total emission levels as given below

- **Annual emission limit**

This constraint states that the sum of the emissions from all the plants must be less than the upper limit on the allowable annual maximum emission level

$$\sum_{\substack{k=1 \\ k \neq hydro}}^{K} \sum_{v=-V}^{t} \sum_{s=1}^{S} \sum_{p=1}^{P} Emf_{nk} \times U_{kpstv} \times N_{st} \times \theta_{pst} + \sum_{\substack{j=1 \\ j \neq hydro}}^{J} \sum_{v=-V}^{t} \sum_{s=1}^{S} \sum_{p=1}^{P} Emf_{nj} \times U_{jpstv} \times N_{st} \times \theta_{pst} \leq Ema_{nt} \quad \text{for all } t\ n$$

(4 1)

Where

Emf_{nk} Emission of pollutant n per unit energy generation in plant type k

U_{kpstv} Power generation from plant k of vintage v in block p of season s in year t

N_{st} Number of days in season s of year t

θ_{pst} Width of block p of chronological load curve of season s in year t

Emf_{nj} Emission of pollutant n per unit energy generation in plant type j

U_{jpstv} Power generation from candidate plant j of vintage v in block p of season s in year t

Ema_{nt} Upper limit of annual emission of pollutant n in year t

All the data of NREB system used in chapters 2&3 are also required for the case studies in this chapter The additional datas required are the emission constraint data as given in the Annex D These emission data have been entered for each year basis of the planning period i e from 2003 to 2017 Zero has been entered in the total emission limit block of the data format as the emission datas were required to be entered for each year basis only

4 3 Case Studies and Results

Two sets of case studies were carried out on the NRSB system in this chapter pertaining to the 5% and 10% reduction of total CO_2 emission from the plants The results for these two cases and for the sensitivity analyses are given below

4 3 1 Case 1 Mitigation target of 5% over BAU

4 3 1 1 Base case

For this study the base case data utilized are same as for the business as usual (BAU 1) case in the chapter 3 i e after considering IGCC and PFBC plants The emission targets (Emqnt in eq (4 1)) is computed for each planning year as 95% of the CO_2 emission value for that year corresponding to the BAU case in chapter The planning results listing the selected plants along with various cost components are given in Table 4 1 and summary of the cost and emission values in Table 4 2 Comparing the results of Table 4 1 & 4 2 with Tables 3 1 & 3 2 and also with the Table 2 5 & 2 6 provide the following observations

1) The selection of hydro PFBC and IGCC plants remain same for case studies with and without emission constraints More number of CCGT and nuclear plants were selected in case of 5% mitigation where as the coal plants selected were less than the least cost generation expansion planning with efficient technologies Comparing with the BAU case without efficient technologies the number of CCGT and nuclear plants selected has increased and the coal plants have decreased

2) The total cost in the case of least cost generation expansion planning with 5%

mitigation was around 2% more than the least cost generation expansion planning with efficient technologies Comparing with the BAU case the cost is only 0 1% more

3) The reduction in the total emissions of CO_2 SO_2 and NO_x over the least cost generation expansion planning with efficient technologies are 3% 6% and 2% respectively Compared to the BAU case (chapter 2) the SO_2 and NO_x emissions reduces by 17% and 11% respectively

TABLE 4 1 Plant selection with 5% mitigation target

GENERATION EXPANSION PLAN

Year	Plant Selection		Discounted cap cost (k$)	Salvage value (k$)	Net capital Cost (k$)	Nominal cost (k$)
2003	COAL 500	(33 x 500 MW)	10245201 83	1348940 92	8896260 91	16500000 00
2003	CCGT-250	(15 x 250 MW)	1811537 96	199554 07	1611983 89	2917500 00
2004	COAL 500	(1 x 500 MW)	282236 97	43106 65	239130 31	500000 00
2004	HYDRO-250 35%	(5 x 250 MW)	705592 41	133779 27	571813 15	1250000 00
2005	PFBC 500	(2 x 450 MW)	541638 39	95701 72	445936 67	1055500 00
2005	IGCC 500	(2 x 400 MW)	570169 99	100745 70	469424 29	1111100 00
2006	PFBC 500	(2 x 450 MW)	492398 54	100408 77	391989 77	1055500 00
2006	HYDRO-250 35%	(5 x 250 MW)	583134 23	141211 45	441922 78	1250000 00
2007	PFBC 500	(6 x 450 MW)	1342905 11	315347 46	1027557 65	3166500 00
2008	NUCLEAR-500	(2 x 500 MW)	513543 66	138535 86	375007 80	1332000 00
2008	IGCC 500	(5 x 400 MW)	1070942 87	289025 15	781917 72	2777750 00
2008	HYDRO-250 35%	(5 x 250 MW)	481929 11	148643 63	333285 48	1250000 00
2009	COAL 500	(5 x 500 MW)	876234 75	271274 62	604960 13	2500000 00
2009	IGCC 500	(3 x 400 MW)	584150 66	180847 27	403303 39	1666650 00
2010	COAL 500	(8 x 500 MW)	1274523 27	451876 63	822646 64	4000000 00
2010	HYDRO-250 35%	(5 x 250 MW)	398288 52	156075 81	242212 71	1250000 00
2011	COAL 500	(9 x 500 MW)	1303489 71	528428 10	775061 61	4500000 00
2012	COAL 500	(9 x 500 MW)	1184990 64	548494 99	636495 66	4500000 00
2012	HYDRO-250 35%	(5 x 250 MW)	329164 07	163507 99	165656 08	1250000 00
2013	COAL 500	(10 x 500 MW)	1196960 25	631735 42	565224 83	5000000 00
2014	COAL 500	(10 x 500 MW)	1088145 68	654031 96	434113 72	5000000 00
2014	HYDRO-250 35%	(5 x 250 MW)	272036 42	170940 17	101096 25	1250000 00
2015	COAL 500	(12 x 500 MW)	1187068 01	811594 21	375473 80	6000000 00
2016	COAL 500	(13 x 500 MW)	1169082 13	908212 57	260869 57	6500000 00
2016	NUCLEAR-500	(1 x 500 MW)	119785 95	93050 91	26735 04	666000 00
2017	COAL 500	(13 x 500 MW)	1062801 94	937198 07	125603 87	6500000 00
2017	NUCLEAR-500	(1 x 500 MW)	108896 32	96023 78	12872 54	666000 00
Total capital cost					21138556 25	85414500 00

Table 4 2 Summary of the total cost and emission levels with 5% mitigation target

ANNUAL DISCRIPTION

Year	Capital(k$)	Fix O&M (k$)	Fuel & Var (k$)	Annual Total	CO2(Gg)	SO2(Mg)	NOX(Mg)
2003	10508244 8(72 %)	754038 6(5 %)	3391973 2(23 %)	14654256 6	195960 0	1096428 7	533977 7
2004	810943 5(19 %)	691948 1(16 %)	2802550 0(65 %)	4305441 5	205010 0	1166010 7	555069 4
2005	915361 0(22 %)	651566 1(15 %)	2673072 9(63 %)	4240000 0	221150 0	1227869 1	585617 3
2006	833912 5(21 %)	602901 2(15 %)	2522992 3(64 %)	3959806 1	230997 7	1253658 8	601104 0
2007	1027557 7(25 %)	576914 9(14 %)	2426008 0(60 %)	4030480 6	247702 3	1258475 1	612777 7
2008	1490211 0(34 %)	556846 4(13 %)	2293949 2(53 %)	4341006 6	254923 3	1261502 1	620309 1
2009	1008263 5(27 %)	537439 3(14 %)	2244587 2(59 %)	3790290 0	274857 7	1351031 2	664219 0
2010	1064859 4(28 %)	517746 3(14 %)	2160820 1(58 %)	3743425 8	296507 9	1481860 1	715524 3
2011	775061 6(23 %)	500506 3(15 %)	2123941 3(62 %)	3399509 2	323134 3	1633766 6	780808 3
2012	802151 7(24 %)	482122 0(14 %)	2050684 3(61 %)	3334958 0	348291 3	1784604 4	841710 9
2013	565224 8(19 %)	465682 9(15 %)	2018408 0(66 %)	3049315 8	378636 6	1958064 2	917128 5
2014	535210 0(18 %)	448248 2(15 %)	1951060 5(66 %)	2934518 7	406994 7	2123751 8	985991 0
2015	375473 8(14 %)	434662 2(16 %)	1911447 5(70 %)	2721583 5	441932 9	2328232 7	1071363 3
2016	287604 6(11 %)	424677 8(17 %)	1853629 1(72 %)	2565911 5	477515 2	2541294 7	1156478 1
2017	138476 4(6 %)	412916 5(18 %)	1806320 0(77 %)	2357712 9	514230 0	2752915 5	1245713 6
Total	21138556 3(33 %)	8058217 8(13 %)	34231444 6(54 %)	63428216 7	4817843 8	25219465 7	11887792 1

4 3 1 2 Sensitivity analyses

In order to study the impact of change in the values of various assumed parameters on the planning results with the mitigation target of 5% on CO_2 emission sensitivity analyses were carried out with respect to different parameters These are described below

a) Discount rate

The discount rate was varied by +50% and –50% of the base case value and the summary of results obtained are given in Table 4 3 It can be observed that in both the cases all hydro nuclear PFBC and IGCC plants were selected With reduction in the discount rate total cost has drastically increased where as there is a marginal change in the emissions level

Table 4 3 Results with change in discount rate with 5% mitigation

Discount Rate in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+50%	122	16	4	30	10	10	42 07	4 81	25 07	11 87
50%	124	14	4	30	10	10	99 20	4 8	25 24	11 73

b) Fuel price

Fuel prices were changed by following percentage

A) ±10% in the coal price

B) ±25% and ±50% in the oil price

C) ±25% and only +50% in the gas price

The summary of results are given in Table 4 4 It can be observed that the total cost varies with change in gas and coal prices where as it is almost same with change in

the oil price More number of CCGT plants are selected with reduction in gas price The variation in the emission levels are not substantial in all the cases

Table 4 4 Results with change in fuels cost with 5% mitigation

Type of fuels	Cost in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
Coal	+10	122	16	4	30	10	10	65 76	4 80	24 97	11 83
Coal	10	123	15	4	30	10	10	61 07	4 82	25 13	11 89
Oil	+25	122	16	4	30	10	10	63 47	4 81	25 21	11 89
Oil	25	122	16	4	30	10	10	63 38	4 81	25 21	11 89
Oil	+50	122	16	4	30	10	10	63 51	4 81	25 21	11 89
Oil	50	122	16	4	30	10	10	63 34	4 80	25 09	11 87
Gas	+25	123	15	4	30	10	10	64 30	4 87	25 80	11 90
Gas	25	120	22	2	30	10	10	61 26	4 78	24 74	11 82
Gas	+50	123	14	4	30	10	10	66 64	4 87	26 02	11 87

c) Power demand

The power demand was changed by –20% of the base case value The result of plants selected total cost and various emissions are given in the Table 4 5 The programme gave convergence problem with +25% variation in the demand It is observed that reduction in power demand reduces the conventional thermal power plants selection as candidate plants

Table 4 5 Results with change in power demand with 5% mitigation

Percentage in power demand on BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO_x emission in GKg
20%	85	2	2	30	10	10	47 03	3 80	19 80	9 26

d) Supply side capital cost

Supply side capital cost was changed by ±20% and only –40% for the case study The results are given in the Table 4 6 In all the cases total cost for generation varies considerably No significant change in the emission level is observed

Table 4 6 Results with change in supply side capital costs with 5% mitigation

Supply side capital cost in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+20%	122	16	4	30	10	10	67 65	4 80	25 08	11 87
20%	123	15	4	30	10	10	59 19	4 81	25 22	11 88
40%	123	15	4	30	10	10	54 79	4 81	25 32	11 75

e) Generation efficiency of new power plant

In this case the change in efficiency of the PFBC and IGCC type plants were considered The plants efficiency has been changed +2% and +5% and then the package ran The results are provided in the table 4 7 in this case there is practically no change in the planning results

Table 4 7 Results with change in generation efficiency with 5% mitigation

Change in generation efficiency	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+2%	122	16	4	30	10	10	63 37	4 81	25 21	11 89
+5%	122	16	4	30	10	10	63 30	4 81	25 22	11 89

4 3 2 Case 2 Mitigation Target of 10% over BAU

This case is same as Case 1 except that the CO_2 emission reduction target is set at 10% over the BAU case The emission targets (Emqnt of eq (4 1)) is computed as the 90% of the total CO_2 emission for the BAU case (chapter 2) for each year of the planning years The results of the base case are given below

4 3 2 1 Base Case

Base case utilizes all the data of BAU 1 case in chapter 3 and the emission constraints The planning results listing the selected plants along with various cost components are given in Table 4 8 and summary of the cost and emission values in Table 4 9 Comparing the results of Table 4 8 & 4 9 with Tables 3 1 & 3 2 and Table 2 5 & 2 6 following observations are made

1) The selection of hydro PFBC and IGCC plants remain same in all the three cases There is considerable increase in the selection of CCGT plants The number of CCGT and nuclear plants selected in case of the 10% mitigation target are 53 & 4 respectively and in the case of BAU 1 with efficient technologies there are 2 % 2 only The number of coal plants selected gets reduced

2) The total cost in the case of least cost generation expansion planning with 10% mitigation target is around 4% more than the least cost generation expansion planning with efficient technologies Total cost is also increased by 3% approximately than the BAU case of chapter 2

3) The reduction in emissions of CO_2 SO_2 and NO_x as compared to the least cost generation expansion planning with efficient technologies are around 8% 18% and 6% respectively The emission of SO_2 and NO_x are 25% and 14% less than the BAU case in chapter 2, respectively

TABLE 4 8 Plant selection with 10% mitigation target

GENERATION EXPANSION PLAN

Year	Plant Selection		Discounted cap cost (k$)	Salvage value (k$)	Net capital Cost (k$)	Nominal cost (k$)
2003	COAL 500	(25 x 500 MW)	7761516 54	1021924 94	6739591 60	12500000 00
2003	CCGT-250	(29 x 250 MW)	3502306 72	385804 54	3116502 19	5640500 00
2004	COAL 500	(1 x 500 MW)	282236 97	43106 65	239130 31	500000 00
2004	CCGT-250	(1 x 250 MW)	109790 18	14344 11	95446 07	194500 00
2004	HYDRO-250 35%	(5 x 250 MW)	705592 41	133779 27	571813 15	1250000 00
2005	PFBC 500	(2 x 450 MW)	541638 39	95701 72	445936 67	1055500 00
2005	IGCC 500	(2 x 400 MW)	570169 99	100745 70	469424 29	1111100 00
2006	PFBC 500	(2 x 450 MW)	492398 54	100408 77	391989 77	1055500 00
2006	HYDRO-250 35%	(5 x 250 MW)	583134 23	141211 45	441922 78	1250000 00
2007	PFBC 500	(6 x 450 MW)	1342905 11	315347 46	1027557 65	3166500 00
2008	NUCLEAR-500	(2 x 500 MW)	513543 66	138535 86	375007 80	1332000 00
2008	IGCC 500	(5 x 400 MW)	1070942 87	289025 15	781917 72	2777750 00
2008	HYDRO-250 35%	(5 x 250 MW)	481929 11	148643 63	333285 48	1250000 00
2009	COAL 500	(5 x 500 MW)	876234 75	271274 62	604960 13	2500000 00
2009	IGCC 500	(3 x 400 MW)	584150 66	180847 27	403303 39	1666650 00
2010	COAL 500	(8 x 500 MW)	1274523 27	451876 63	822646 64	4000000 00
2010	HYDRO-250 35%	(5 x 250 MW)	398288 52	156075 81	242212 71	1250000 00
2011	COAL 500	(9 x 500 MW)	1303489 71	528428 10	775061 61	4500000 00
2012	COAL 500	(7 x 500 MW)	921659 39	426607 21	495052 18	3500000 00
2012	NUCLEAR-500	(2 x 500 MW)	350757 23	162318 84	188438 39	1332000 00
2012	HYDRO-250 35%	(5 x 250 MW)	329164 07	163507 99	165656 08	1250000 00
2013	COAL 500	(10 x 500 MW)	1196960 25	631735 42	565224 83	5000000 00
2013	CCGT-250	(1 x 250 MW)	46561 75	23708 66	22853 09	194500 00
2014	COAL 500	(9 x 500 MW)	979331 11	588628 77	390702 34	4500000 00
2014	CCGT-250	(2 x 250 MW)	84657 73	49498 33	35159 41	389000 00
2014	HYDRO-250 35%	(5 x 250 MW)	272036 42	170940 17	101096 25	1250000 00
2015	COAL 500	(10 x 500 MW)	989223 34	676328 51	312894 84	5000000 00
2015	CCGT-250	(4 x 250 MW)	153923 15	103158 68	50764 47	778000 00
2016	COAL 500	(9 x 500 MW)	809364 55	628762 55	180602 01	4500000 00
2016	CCGT-250	(7 x 250 MW)	244877 74	187811 22	57066 52	1361500 00
2017	COAL 500	(9 x 500 MW)	735785 96	648829 44	86956 52	4500000 00
2017	CCGT-250	(9 x 250 MW)	286220 74	250836 12	35384 62	1750500 00

Total capital cost 20565561 50 82305500 00

Table 4 9 Summary of the total cost and emission levels with 10% mitigation target

ANNUAL DISCRIPTION

Year	Capital(k$)	F_x O&M (k$)	Fuel & Var (k$)	Annual Total	CO2(Gg)	SO2(Mg)	NOX(Mg)
2003	9856093 8(69 %)	738728 8(5 %)	3634035 6(26 %)	14228858 2	186650 0	983983 5	520758 2
2004	906389 5(20 %)	680726 5(15 %)	3016832 8(66 %)	4603948 9	194220 0	1030984 7	536047 4
2005	915361 0(21 %)	641364 7(15 %)	2859518 4(65 %)	4416244 0	209510 0	1091871 6	563470 4
2006	833912 5(20 %)	593627 2(14 %)	2690685 6(65 %)	4118225 4	219620 0	1119843 8	579887 3
2007	1027557 7(25 %)	568484 0(14 %)	2577611 9(62 %)	4173653 6	237028 2	1132897 1	593492 5
2008	1490211 0(33 %)	549181 9(12 %)	2431771 0(54 %)	4471163 9	244249 1	1135924 1	601023 9
2009	1008263 5(26 %)	530471 6(14 %)	2370241 7(61 %)	3908976 8	264196 1	1225636 0	644959 3
2010	1064859 4(28 %)	511412 0(13 %)	2274722 4(59 %)	3850993 8	285833 8	1356282 1	696239 1
2011	775061 6(22 %)	494747 9(14 %)	2227488 8(64 %)	3497298 3	312460 1	1508188 6	761523 1
2012	849146 6(25 %)	478996 1(14 %)	2135350 9(62 %)	3463493 6	332440 0	1625807 5	810124 1
2013	588077 9(19 %)	463984 7(15 %)	2092798 0(67 %)	3144860 6	362567 6	1796688 1	884808 3
2014	526958 0(18 %)	446293 6(15 %)	2030553 0(68 %)	3003804 6	389547 8	1947151 1	950619 5
2015	363659 3(13 %)	432138 2(15 %)	2000704 9(72 %)	2796502 5	421220 0	2114775 7	1028376 0
2016	237668 5(9 %)	417387 8(16 %)	1981749 1(75 %)	2636805 4	453580 0	2274655 0	1111238 9
2017	122341 1(5 %)	403310 0(16 %)	1959617 4(79 %)	2485268 5	487025 0	2432019 5	1197881 7
Total	20565561 4(32 %)	7950855 0(12 %)	36283682 5(56 %)	64800098 0	4600147 8	22776708 4	11480449 7

4 3 2 2 Sensitivity analyses

The sensitivity analysis results with respect to different parameters for the 10% CO_2 level mitigation are given below

a) Discount rate

The discount rate was varied by +50% and –50% of the base case value and the summary of results obtained were given in Table 4 10 It can be observed that in both the cases all coal based thermal plants and hydro plants were selected With reduction in the discount rate total cost has considerably increased where as there is a marginal change in the emission level

Table 4 10 Results with change in discount rate with 10% mitigation

Discount Rate in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+50%	102	53	4	30	10	10	42 78	4 60	22 79	11 50
50%	103	52	4	30	10	10	102 03	4 60	22 87	11 35

b) Fuel price

Fuel prices were changed by following percentage

- ±10% in the coal price
- ±25% and ±50% in the oil price
- ±25% and only +50% in the gas price

The summary of results are given in Table 4 11

Table 4 11 Results with change in fuels cost with 10% mitigation

Type of fuels	Cost in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
Coal	+10	102	53	4	30	10	10	66 87	4 59	22 77	11 47
Coal	10	102	53	4	30	10	10	62 69	4 60	22 83	11 50
Oil	+25	103	52	4	30	10	10	64 84	4 60	22 82	11 48
Oil	25	102	53	4	30	10	10	64 74	4 60	22 81	11 48
Oil	+50	103	52	4	30	10	10	64 89	4 60	22 82	11 49
Oil	50	103	52	4	30	10	10	64 57	4 60	22 81	11 47
Gas	+25	102	53	4	30	10	10	67 83	4 62	23 05	11 44
Gas	25	100	60	2	30	10	10	61 51	4 58	22 31	11 44
Gas	+50	103	52	4	30	10	10	70 49	4 62	23 08	11 38

a) Power demand

The power demand was changed by –20% of the base case value The result of plants selected total cost and various emissions are given in the Table 4 12

Table 4 12 Results with change in power demand with 10% mitigation

Percentage in power demand on BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+20%	85	2	2	30	10	10	46 62	3 77	19 72	9 20

b) Supply side capital cost

Supply side capital cost was changed by ±20% and only –40% for the case study The result is given in the Table 4 13

Table 4 13 Results with change in supply side capital costs with 10% mitigation

Supply side capital cost in % of BAU case	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+20%	102	53	4	30	10	10	68 92	4 60	22 78	11 14
20%	103	52	4	30	10	10	60 68	4 60	22 83	11 49
40%	102	53	4	30	10	10	56 38	4 61	23 02	11 38

e) **Generation efficiency of new power plant**

In this case the change in efficiency of the PFBC and IGCC type plants were considered The plants efficiency has been changed +2% and +5% and then the package ran for the analysis result The results were provided in the table 4 14

Table 4 14 Results with change in generation efficiency with 10% mitigation

Change in generation efficiency	No of Coal 500MW selected	No of CCGT 250 selected	No of Nuclear 500MW selected	No of Hydro 250 35%	No of PFBC plants selected	No of IGCC plants selected	Total cost in G$	CO_2 emission in TKg	SO_2 emission in GKg	NO emission in GKg
+2%	102	53	4	30	10	10	64 74	4 60	22 81	11 48
+5%	103	52	4	30	10	10	64 67	4 60	22 81	11 48

4 4 Conclusion

The least cost generation expansion planning with the mitigation of 10% of GHG from the base case was studied on NREB system

- The hydro CCGT and PFBC plants selected were same for all the cases

- On change in discount rate the cost varies more in quantity and the other parameters are varied marginally
- The Highest CCGT nuclear plant selected and lowest coal plant selected with the – 25% decrease in coal price Total cost is highest on increase in gas price Emission levels are approximately constant
- Change in power demand affect exactly in the same manner that of the case of 5%mitigation
- With rise in supply side cost the total cost is rising and reduction of capital cost reduces the total cost
- Change in efficiency has significantly no effect

CHAPTER 5

CONCLUSION

Greenhouse Gas (GHG) mitigation has been considered as one of the major concerns of the environment protection through out the world with respect to the global warming Since the power plants are one of the main contributors to such gases it is important to integrate this objective in the future expansion plans This thesis has made extensive studies of generation expansion planning incorporating the carbon dioxide (CO_2) emission mitigation constraint in the least cost model and also exploring the impact of two types of efficient supply side technology options viz Pressurized Fluidized Bed Combustion (PFBC) and Integrated Gasification Combined Cycle (IGCC)

Three different case studies considered were the traditional least cost planning least cost planning with efficient technologies and least planning with CO_2 emission mitigation constraint Mitigation reduction targets of 5% and 10% were considered over the Business As Usual (BAU) case Various sensitivity analyses were also carried out with respect to the change in discount rate fuel prices power demand supply side capital cost and efficiency of efficient plants The results obtained on the Northern regional Electricity Board (NREB) network using the IRPA package for 15 years planning horizon provide following main conclusions

- All the hydro plants have been fully selected in each of the case studies This is due to consideration of zero operating cost and no emission from these plants
- All candidate coal type plants were selected in the BAU and associated sensitivity analyses cases due to their lower cost However with the use of plants having efficient technologies and in GHG mitigation cases selection of number of coal based plants reduced

- More number of CCGT and nuclear plants were selected in the cases having constraint on GHG mitigation due to relatively less pollution from these plants
- With the use of efficient technologies such as PFBC and IGCC the reduction in cost as well as all types of pollutants i e CO_2 SO_2 and NO_x were observed Number of such plants selected remained same even with variation of different parameters
- With the GHG emission limit constraint (only CO_2 in this study) included in the planning methodology significant cost reduction in the total emissions of CO_2 NO_x and SO_2 were observed over the BAU as well as BAU 1 cases both for the 5% and 10% CO_2 mitigation targets The cost of generation in these cases however slightly increases
- It was observed that the total cost increased significantly with the decrease in discount rate However variation in the discount rate has negligible effect on emission levels
- The CO_2 emission level is sensitive to only change in the gas price and remain almost same with change in oil and coal prices The Highest CCGT nuclear plant selected and lowest coal plant selected with the –25% decrease in coal price Total cost is highest on increase in gas price Emission levels are approximately constant
- Number of coal based nuclear and CCGT plants selected reduces considerably with decrease in power demand Total cost and emission varies according to power demand
- Supply side cost variation affects the total cost significantly and has no effect on emission levels With increase in the cost it selects more number of CCGT plants and with the reduction in the cost more number of nuclear plants are selected specially in case of least cost planning with GHG (only CO_2) mitigation
- Change in efficiency of the PFBC and IGCC plants by +2% and +5% has practically no effect on plant selection cost and emission levels

Consequent to the generation expansion planning studies carried out in this thesis following areas of future research are identified

- In the present case only two supply side efficient technology options i e PFBC and IGCC have been considered for the emission reduction Other supply side options

as well as demand side options can be considered in the generation expansion planning studies

- The pumped storage hydro plants have not been considered in the present study India has large potential of such plants as well as for many non conventional type plants Such plants can also be considered as candidates in the planning studies
- Many developing countries are encouraging use of distributed generation and adopting the deregulated electricity market These aspects can also be integrated in the generation expansion planning

ANNEX A

Table A 1 Basic Data Form

Optimal Output File: C \ullash\out lp

Base Year	Starting Year	No of Years	No of Seasons	No of Blocks	Discount Factor	No of Fuel Type	No of Plant Types
1998	2003	15	2	20	1 1	10	6

Emission Constraints: NO ⇩ Solver Type: CPLEX ⇩ DSM Case: No Restriction ⇩

Existing Plants			Candidate Plants			DSM	External	GROUPS		
Thermal	Hydro	Pump Stor	Thermal	Hydro	Pump Stor	Option	Suppliers	Thermal	Hydro	DSM
160	230	0	3	6	0	0	0	0	0	0

No of hours of a block of the daily load curve

Block	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Value	1	1	2	1	1	1	1	1	1	1	1	1	4	1	1	1	1	1	1	1

No of Days of season in a year

Season	1	2
Value	92	273

Table A 2 Load Data Form

Normalized load of the block in the season

Sea/ Bloc	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
1	8611	8468	825	8 41	8489	835	8217	8179	8081	8055	8103	8152	83	8313	9674	1 0	9923	9955	8964	8711
2	8663	8521	843	8712	9274	9599	9368	9439	9082	8645	8447	855	8606	9394	1 0	9927	9864	9642	9113	8846

Annual System Load Factor (%)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	65 4	65 7	66 0	65 8	65 9	66 0	66 17	66 3	66 4	66 5	66 6	66 7	66 7	66 7	66 8

Annual System Peak Demand (MW)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	33880	36169	38613	41223	44009	46835	49843	53044	56451	60077	63935	68040	72405	77055	82002

Annual Expected System Reserve Margin (0 00 1 00)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05	0 05

Table A-3 Emission Data Form

Expected CO Emission Limit (Unit = Mtons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total CO Emission Limit During Planning Period 0

Expected SO_2 Emission Limit (Unit = Ktons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total SO_2 Emission Limit During Planning Period 0

Expected NO Emission Limit (Unit = Ktons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total SO_2 Emission Limit During Planning Period 0

Table A-4 Fuel Type Data

	Cost	Cost Multiplication Factor in the Years														
Name	$/Gcal	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Coal 1	3 5	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Coal 2	4.5	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Coal 3	6.5	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Coal-4	7 5	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Coal 5	8 5	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Coal 6	10	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Gas	17	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Nuclear	2 5	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Lignite	3 8	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05
Oil	22	1 2	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05	1 05

Table A 5 Plant Type Data

TYPE	NAME
1	CONVENTIONAL COAL
2	COMBINED CYCLE GAS TURBINE
3	NUCLEAR
4	LIGNITE
5	PFBC
6	IGCC

Table A 8 Candidate Thermal Power Plant Data

Name	COAL 500	CCGT 250	NUCLE 500
Used Fuel Type	COAL	GAS	NUCLEAR
Fuel Consumption Rate Unit	000 Kg/MWh	000 Kg/MWh	000 Kg/MWh
Fuel Consumption	0 7	0 2	0 00027
Calorific Value (KBtu/Kg)	13 5	34 52	40635
CO_2 Emission (Kg/MWh)	1026	550	0
SO_2 Emission (Kg/MWh)	6	0 4	0
NO Emission (Kg/MWh)	2 5	1 64	0
Capacity (MW)	500	250	500
Minimum Operating Capacity (MW)	150	75	125
Earliest Available Year	1	1	4
Annual Allowable Max Unit	150	75	4
Availability	0 71	0 8	0 58
Unit Depreciable Capital Cost (000 $)	450000	175000	600000
Unit Non Depreciable Capital Cost (000 $)	50000	19500	66000
Heat Rate (Mcal/MWh)	2500	2062	2777
Operating Cost (000 $/MWh)	0 0012	0 0008	0 0015
Transmission Loss Rate	0 04	0 04	0 04
Annual Maintenance Hours	864	1296	896
Unit Life Time	30	25	30
Fixed Oper & Maint Cost (000 $/MWmonth)	2	1 67	2 7
Number of the Fuel Type	4	7	8
Number of the Plant Type	1	2	3
Plant Site No	0	0	0
Minimum Selected Units in Year 2003	2	2	0
Max Possible Incremental Units in Year 2003	150	75	0
Minimum Selected Units in Year 2004	2	2	0
Max Possible Incremental Units in Year 2004	150	75	0
Minimum Selected Units in Year 2005	2	2	0
Max Possible Incremental Units in Year 2005	150	75	0
Minimum Selected Units in Year 2006	2	2	0
Max Possible Incremental Units in Year 2006	150	75	0
Minimum Selected Units in Year 2007	2	2	0
Max Possible Incremental Units in Year 2007	150	75	0
Minimum Selected Units in Year 2008	2	2	2
Max Possible Incremental Units in Year 2008	150	75	4
Minimum Selected Units in Year 2009	2	2	2
Max Possible Incremental Units in Year 2009	150	75	4
Minimum Selected Units in Year 2010	2	2	2

Max Possible Incremental Units in Year 2010	150	75	4
Minimum Selected Units in Year 2011	2	2	2
Max Possible Incremental Units in Year 2011	150	75	4
Minimum Selected Units in Year 2012	2	2	2
Max Possible Incremental Units in Year 2012	150	75	4
Minimum Selected Units in Year 2013	2	2	2
Max Possible Incremental Units in Year 2013	150	75	4
Minimum Selected Units in Year 2014	5	2	2
Max Possible Incremental Units in Year 2014	150	75	4
Minimum Selected Units in Year 2015	5	2	2
Max Possible Incremental Units in Year 2015	150	75	4
Minimum Selected Units in Year 2016	2	2	2
Max Possible Incremental Units in Year 2016	150	75	4
Minimum Selected Units in Year 2017	2	2	2
Max Possible Incremental Units in Year 2017	150	75	4

Table A 9 Candidate Hydro Power Plant Data

Candidate Hydro Plant No	1
Name Efficiency	Hydro 250 35%
Unit Capacity (MW)	250
Earliest Possible Available Year	2
Maximum Units	5
Availability	0 9
Unit Capital Cost (000 $)	250000
Operating Cost (000 $/MWh)	0
Transmission Loss Rate	0 04
Life Time	50
Fixed Oper & Maint Cost (000 $/MWmonth)	0
Plant Development No	0
Plant Phase Order	0
Available Energy in Season 1 (MWh)	262800
Available Energy in Season 2 (MWh)	613200

Table A 6 Existing Thermal Power Plant Data

NAME	Fuel Type	Fuel Con	Cal Value (kBtu/kg)	CO2 Emis (kg/MWh)	SO2 Emis (kg/MWh)	NOx Emis. (kg/MWh)	Capacity (MW)	EA Year	Avail	Heat Rate (kcal/kwh)	Oper Cost (000 $/MWh)	Annual Maint. Hours	Fixed O&M (000 $/Mwmonth)	Fuel Type
BADARPUR1	COAL	0 8	14 27	1144	8	5 14	85	2003	0 6	3213	0 0012	864	2	3
BADARPUR2	COAL	0 8	14 27	1144	8	5 14	85	2003	0 6	3213	0 0012	864	2	3
BADARPUR3	COAL	0 8	14 27	1144	8	5 14	85	2003	0 6	3213	0 0012	864	2	3
BADARPURXT 1	COAL	0 7	14 27	1001	7	4 45	190	2003	0 71	2781	0 0012	864	2	3
BADARPURXT 2	COAL	0 7	14 27	1001	7	2 78	190	2003	0 71	2781	0 0012	864	2	3
IP 60	COAL	0 85	15 19	1277 83	8 5	5 82	54	2003	0 6	3636	0 0012	864	2	3
IP 1	COAL	0 85	15 19	1277 83	8 5	5 82	56	2003	0 6	3636	0 0012	864	2	3
IP 2	COAL	0 85	15 19	1277 83	8 5	5 82	56	2003	0 6	3636	0 0012	864	2	3
IP 3	COAL	0 85	15 19	1277 83	8 5	5 82	56	2003	0 6	3636	0 0012	864	2	3
RAJGHAT 2	COAL	0 82	17 65	1473 27	8 2	6 52	61	2003	0 6	4075	0 0012	864	2	3
RAJGHAT 3	COAL	0 82	17 65	1473 27	8 2	6 52	60	2003	0 6	4075	0 0012	864	2	3
GAS DESU 1WH	GAS	0 221	41 74	504 43	0 37	1 59	45 5	2003	0 71	1982	0 0008	1296	1 67	7
GAS DESU 2WH	GAS	0 221	41 74	504 43	0 37	1 59	45 5	2003	0 71	1982	0 0008	1296	1 67	7
GAS DESU 3WH	GAS	0 221	41 74	504 43	0 37	1 59	45 5	2003	0 71	1982	0 0008	1296	1 67	7
GAS DESU 4WH	GAS	0 221	41 74	504 43	0 37	1 59	45 5	2003	0 71	1982	0 0008	1296	1 67	7
GAS DESU 5WH	GAS	0 221	41 74	504 43	0 37	1 59	45 5	2003	0 71	1982	0 0008	1296	1 67	7
GAS DESU 6WH	GAS	0 221	41 74	504 43	0 37	1 59	45 5	2003	0 71	1982	0 0008	1296	1 67	7
FARIDABADXT1	COAL	0 9	17 88	1617	9	7 25	49	2003	0 6	4530	0 0012	864	2	5
FARIDABADXT2	COAL	0 9	17 88	1617	9	7 25	49	2003	0 6	4530	0 0012	864	2	5
FARIDABADXT3	COAL	0 9	17 88	1617	9	7 25	49	2003	0 6	4530	0 0012	864	2	5
PANIPAT 1	COAL	0 9	15 34	1353	9	3 89	98	2003	0 6	3887	0 0012	864	2	4
PANIPAT 2	COAL	0 9	15 34	1353	9	3 89	98	2003	0 6	3887	0 0012	864	2	4
PANIPAT 3	COAL	0 9	15 34	1353	9	3 89	98	2003	0 6	3887	0 0012	864	2	4
PANIPAT 4	COAL	0 9	15 34	1353	9	3 89	98	2003	0 6	3887	0 0012	864	2	4
PANIPAT 5	COAL	0 85	15 34	1277 83	8 5	3 63	190	2003	0 71	3630	0 0012	864	2	4
FARIDABADCCGT A	GAS	0 221	41 74	504 43	0 37	1 59	139	2003	0 71	1982	0 0008	1296	1 67	7

PAMPORE 1GT	OIL	0 3	42.66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
PAMPORE 2GT	OIL	0 3	42 66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
PAMPORE 3GT	OIL	0 3	42 66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
PAMPORE-4GT II	OIL	0 3	42 66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
PAMPORE 5GT II	OIL	0 3	42 66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
PAMPORE-6GT II	OIL	0 3	42 66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
PAMPORE 7GT II	OIL	0 3	42 66	935	6	2 42	25	2003	0 8	3030	0 0008	1296	1 67	10
BHATINDAlehmoh1	COAL	0 75	15 82	1155	7 5	3 3	190	2003	0 71	3303	0 0012	864	2	6
BHATINDAlehmoh2	COAL	0 75	15 82	1155	7 5	3 3	190	2003	0 71	3303	0 0012	864	2	6
GNDTP 1	COAL	0 75	15 82	1155	7 5	3 34	98	2003	0 68	3340	0 0012	864	2	5
GNDTP 2	COAL	0 75	15 46	1155	7 5	3 27	98	2003	0 68	3265	0 0012	864	2	5
GNDTP 3	COAL	0 75	15 46	1155	7 5	3 27	98	2003	0 68	3265	0 0012	864	2	5
GNDTP-4	COAL	0 75	15 46	1155	7 5	3 27	98	2003	0 68	3265	0 0012	864	2	5
ROPAR I/1	COAL	0 67	15 38	1031 8	6 7	2.87	190	2003	0 71	2870	0 0012	864	2	5
ROPAR I/2	COAL	0 67	15 38	1031 8	6 7	2 87	190	2003	0 71	2870	0 0012	864	2	5
ROPAR II/1	COAL	0 67	15 38	1031 8	6 7	2 87	190	2003	0 71	2870	0 0012	864	2	5
ROPAR II/2	COAL	0 67	15 38	1031 8	6 7	2 87	190	2003	0 71	2870	0 0012	864	2	5
ROPAR IIIXT 1	COAL	0 67	15 38	1031 8	6 7	2 87	190	2003	0 71	2870	0 0012	864	2	5
ROPAR IIIXT 2	COAL	0 67	15 38	1031 8	6 7	2 87	190	2003	0 71	2870	0 0012	864	2	5
KOTA 1	COAL	0 7	16 27	1103 67	7	3 21	98	2003	0 68	3207	0 0012	864	2	5
KOTA 2	COAL	0 7	16 27	1103 67	7	3 21	98	2003	0 68	3207	0 0012	864	2	5
KOTAXT 3	COAL	0 64	16 27	1009 07	6 4	2 9	190	2003	0 71	2899	0 0012	864	2	5
KOTAXT-4	COAL	0 64	16 27	1009 07	6 4	2 9	190	2003	0 71	2899	0 0012	864	2	5
KOTAXT 5	COAL	0 64	16 27	1009 07	6 4	2 9	190	2003	0 71	2899	0 0012	864	2	5
SURATGARHTPS I 1	COAL	0 46	16 27	725 27	4 6	2 08	226	2003	0 71	2084	0 0012	864	2	5
ANTAGAS 1	GAS	0 221	41 74	504 43	0 37	1 59	85	2003	0 71	1982	0 0008	1296	1 67	7
ANTAGAS 2	GAS	0 221	41 74	504 43	0 37	1 59	85	2003	0 71	1982	0 0008	1296	1 67	7
ANTAGAS 3	GAS	0 221	41 74	504 43	0 37	1 59	85	2003	0 71	1982	0 0008	1296	1 67	7
ANTAGAS 4	GAS	0 221	41 74	504 43	0 37	1 59	145	2003	0 71	1982	0 0008	1296	1 67	7
RAMGARHGAS	GAS	0 221	41 74	504 43	0 37	1 55	3	2003	0 71	1942	0 0008	1296	1 67	7
RAMGARHGAS	GAS	0 221	41 74	504 43	0 37	1 55	35	2003	0 71	1942	0 0008	1296	1 67	7
RAPP 1	NUCL	0 027	406350	0	0	0	90	2003	0 58	3072	0 0015	864	2 7	8
RAPP 2	NUCL	0 027	406350	0	0	0	180	2003	0 58	3072	0 0015	864	2 7	8

ANPARA A 1	COAL	0 75	16 08	1155	7 5	3 36	190	2003	0 71	3357	0 0012	864	2	1
ANPARA A 2	COAL	0 75	16 08	1155	7 5	3 36	190	2003	0 71	3357	0 0012	864	2	1
ANPARA A 3	COAL	0 75	16 08	1155	7 5	3 36	190	2003	0 71	3357	0 0012	864	2	1
ANPARA'B 1	COAL	0 6	16 08	924	6	2 64	460	2003	0 71	2642	0 0012	864	2	1
ANPARA B 2	COAL	0 6	16 08	924	6	2 64	460	2003	0 71	2642	0 0012	864	2	1
H GANJB-1	COAL	2003	17 88	1796 67	10	8 06	36	2003	0 45	5036	0 0012	864	2	2
H GANJB-3	COAL	0 9	17 88	1617	9	7 25	54	2003	0 45	4532	0 0012	864	2	2
H GANJB-2	COAL	2003	17 88	1796 67	10	8 06	36	2003	0 45	5036	0 0012	864	2	2
H GANJB-4	COAL	0 9	17 88	1617	9	7 25	54	2003	0 45	4532	0 0012	864	2	2
H GANJC-1	COAL	0 9	17 88	1617	9	7 25	54	2003	0 45	4532	0 0012	864	2	2
H GANJC-2	COAL	0 9	17 88	1617	9	7 25	54	2003	0 45	4532	0 0012	864	2	2
H GANJC-3	COAL	0 89	17 88	1599 03	8 9	7 17	94	2003	0 45	4482	0 0012	864	2	2
NCR 1DADRI	COAL	0 64	15 08	938 67	6 4	2 69	190	2003	0 71	2687	0 0012	864	2	4
NCR 2	COAL	0 64	15 08	938 67	6 4	2 69	190	2003	0 71	2687	0 0012	864	2	4
NCR 3	COAL	0 64	15 08	938 67	6 4	2 69	190	2003	0 71	2687	0 0012	864	2	4
NCR-4	COAL	0 64	15 08	938 67	6 4	2.69	190	2003	0 71	2687	0 0012	864	2	4
OBRA 1	COAL	2003	15 87	1540	10	7 15	36	2003	0 45	4469	0 0012	864	2	1
OBRA 2	COAL	2003	15 87	1540	10	7 15	36	2003	0 45	4469	0 0012	864	2	1
OBRA 3	COAL	2003	15 87	1540	10	7 15	36	2003	0 45	4469	0 0012	864	2	1
OBRA-4	COAL	2003	15 87	1540	10	7 15	36	2003	0 45	4469	0 0012	864	2	1
OBRA 5	COAL	2003	15 87	1540	10	7 15	36	2003	0 45	4469	0 0012	864	2	1
OBRA 6	COAL	0 8	15 87	1232	8	5 72	84	2003	0 45	3575	0 0012	864	2	1
OBRA 7	COAL	0 8	15 87	1232	8	5 72	84	2003	0 45	3575	0 0012	864	2	1
OBRA 8	COAL	0 8	15 87	1232	8	5 72	84	2003	0 45	3575	0 0012	864	2	1
OBRA 9	COAL	0 7	15 87	1078	7	3 09	181	2003	0 71	3094	0 0012	864	2	1
OBRA 10	COAL	0 7	15 87	1078	7	3 09	181	2003	0 71	3094	0 0012	864	2	1
OBRA 11	COAL	0 7	15 87	1078	7	3 09	181	2003	0 71	3094	0 0012	864	2	1
OBRA 12	COAL	0 7	15 87	1078	7	3 09	181	2003	0 71	3094	0 0012	864	2	1
OBRA 13	COAL	0 7	15 87	1078	7	3 09	181	2003	0 71	3094	0 0012	864	2	1
PANKI 3	COAL	0 7	17 68	1232	7	5 58	94	2003	0 45	3485	0 0012	864	2	2
PANKI-4	COAL	0 7	17 68	1232	7	5 58	94	2003	0 45	3485	0 0012	864	2	2
PANKI 1	COAL	2003	17 68	1760	10	7 97	29	2003	0 45	4979	0 0012	864	2	2
PANKI 2	COAL	2003	17 68	1760	10	7 97	29	2003	0 45	4979	0 0012	864	2	2

PARICHHA 1	COAL	0 89	12 77	1207 43	8 9	3.2	98	2003	0 45	3200	0 0012	864	2	3
PARICHHA 2	COAL	0 89	12 77	1207 43	8 9	3 2	98	2003	0 45	3200	0 0012	864	2	3
RIHANDSTPS 1	COAL	0 6	14 61	858	6	2 4	460	2003	0 71	2401	0 0012	864	2	1
RIHANDSTPS 2	COAL	0 6	14 61	858	6	2 4	460	2003	0 71	2401	0 0012	864	2	1
SINGRAULI 1	COAL	0 7	15 24	1052 33	7	2 97	181	2003	0 71	2971	0 0012	864	2	1
SINGRAULI 2	COAL	0 7	15.24	1052.33	7	2 97	181	2003	0 71	2971	0 0012	864	2	1
SINGRAULI 3	COAL	0 7	15 24	1052 33	7	2 97	181	2003	0 71	2971	0 0012	864	2	1
SINGRAULI-4	COAL	0 7	15 24	1052 33	7	2 97	181	2003	0 71	2971	0 0012	864	2	1
SINGRAULI 5	COAL	0 7	15 24	1052 33	7	2 97	181	2003	0 71	2971	0 0012	864	2	1
SINGRAULI 6	COAL	0 55	15 24	826 83	5 5	2 3	460	2003	0 71	2296	0 0012	864	2	1
SINGRAULI 7	COAL	0 55	15.24	826 83	5 5	2 3	460	2003	0 71	2296	0 0012	864	2	1
TANDA 1	COAL	1 04	11 94	1334 67	10 4	3 5	98	2003	0 45	3495	0 0012	864	2	2
TANDA 2	COAL	1 04	11 94	1334 67	10 4	3 5	98	2003	0 45	3495	0 0012	864	2	2
TANDA 3	COAL	1 04	11 94	1334 67	10 4	3 5	98	2003	0 45	3495	0 0012	864	2	2
TANDA-4	COAL	1 04	11 94	1334 67	10 4	3 5	98	2003	0 45	3495	0 0012	864	2	2
UNCHAHAR 3	COAL	0 7	15 08	1026 67	7	2 94	190	2003	0 71	2939	0 0012	864	2	3
UNCHAHAR 1	COAL	0 7	15 08	1026 67	7	2.94	190	2003	0 71	2939	0 0012	864	2	3
UNCHAHAR 2	COAL	0 7	15 08	1026 67	7	2.94	190	2003	0 71	2939	0 0012	864	2	3
AURIYAGAS 1	GAS	0 221	41 74	504 43	0 37	1 59	109	2003	0 71	1982	0 0008	1296	1 67	7
AURIYAGAS 2	GAS	0 221	41 74	504 43	0 37	1 59	109	2003	0 71	1982	0 0008	1296	1 67	7
AURIYAGAS 3	GAS	0 221	41 74	504 43	0 37	1 59	109	2003	0 71	1982	0 0008	1296	1 67	7
AURIYAGAS-4	GAS	0 221	41 74	504 43	0 37	1 59	109	2003	0 71	1982	0 0008	1296	1 67	7
AURIYAGAS 5	GAS	0 221	41 74	504 43	0 37	1 59	99	2003	0 71	1982	0 0008	1296	1 67	7
AURIYAGAS 6	GAS	0 221	41 74	504 43	0 37	1 59	99	2003	0 71	1982	0 0008	1296	1 67	7
DADRICCGT A 1	GAS	0 221	41 74	504 43	0 37	1 59	127	2003	0 71	1982	0 0008	1296	1 67	7
DADRICCGT A 2	GAS	0 221	41 74	504 43	0 37	1 59	127	2003	0 71	1982	0 0008	1296	1 67	7
DADRICCGT A 3	GAS	0 221	41 74	504 43	0 37	1 59	127	2003	0 71	1982	0 0008	1296	1 67	7
DADRICCGT A 4	GAS	0 221	41 74	504 43	0 37	1 59	127	2003	0 71	1982	0 0008	1296	1 67	7
DADRICCGT B 1WH	GAS	0 221	41 74	504 43	0 37	1 59	142	2003	0 71	1982	0 0008	1296	1 67	7
DADRICCGT B 2WH	GAS	0 221	41 74	504 43	0 37	1 59	142	2003	0 71	1982	0 0008	1296	1 67	7
NAPP 1	NUCL	0 027	406350	0	0	0	198	2003	0 58	2844	0 0015	864	2	8
NAPP 2	NUCL	0 027	406350	0	0	0	198	2003	0 58	2844	0 0015	864	2	8
PANIPAT 6	COAL	0 812	13 49	1190 93	8 12	2 76	190	2003	0 71	2762	0 0012	864	2	5

FARIDABADCCGT A	GAS	0 237	41 74	540 95	0 39	1 65	139	2003	0 71	2062	0 0008	1296	1 67	7
FARIDABADCCGT B	GAS	0 237	41 74	540 95	0 39	1 65	140	2003	0 71	2062	0 0008	1296	1 67	7
SURATGARHTPS-I2	COAL	0 812	13 49	1131 39	8 12	2 76	226	2003	0 71	2762	0 0012	864	2	5
BARSINGSARLIG-1	COAL	0 986	11 11	1265 37	19 72	2 76	226	2003	0 68	2762	0 0012	864	2	9
BARSINGSARLIG-2	COAL	0 986	11 11	1265 37	19 72	2 76	226	2004	0 68	2762	0 0012	864	2	9
ANTA IICCGT 1	GAS	0.237	41 74	540 95	0 39	1 65	107	2003	0 71	2062	0 0008	1296	1 67	7
ANTA IICCGT 2	GAS	0 237	41 74	540 95	0 39	1 65	107	2004	0 71	2062	0 0008	1296	1 67	7
ANTA IICCGT 3	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
ANTA IICCGT-4	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
ANTA IICCGT 5	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
RAPP 3	NUCL	0 027	406350	0	0	0	198	2003	0 58	2777	0 0015	864	2	8
RAPP-4	NUCL	0 027	406350	0	0	0	198	2003	0 58	2777	0 0015	864	2	8
ANPARA C 1	COAL	0 719	15	1054 53	7 19	2 72	460	2003	0 73	2717	0 0012	864	2	1
ANPARA C 2	COAL	0 719	15	1054 53	7 19	2 72	460	2004	0 73	2717	0 0012	864	2	1
RIHAND II 1	COAL	0 679	15 87	1045 66	6 79	2 72	460	2004	0 73	2717	0 0012	864	2	1
RIHAND II 2	COAL	0 679	15 87	1045 66	6 79	2 72	460	2006	0 73	2717	0 0012	864	2	1
ROSAI/1	COAL	0 812	13 49	1131 39	8 12	2 76	257	2003	0 73	2762	0 0012	864	2	3
ROSAI/2	COAL	0 812	13 49	1131 39	8 12	2 76	257	2004	0 73	2762	0 0012	864	2	3
UNCHAHAR-4	COAL	0 691	15 87	1064 14	6 91	2 76	190	2003	0 71	2762	0 0012	864	2	3
AURIYA IICCGT 1	GAS	0.237	41 74	540 95	0 39	1 65	107	2003	0 71	2062	0 0008	1296	1 67	7
AURIYA IICCGT 2	GAS	0 237	41 74	540 95	0 39	1 65	107	2004	0 71	2062	0 0008	1296	1 67	7
AURIYA IICCGT 3	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
AURIYA IICCGT-4	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
AURIYA IICCGT 5	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
GLOBALBOARDCGT	GAS	0 237	41 74	540 95	0 39	1 65	126	2003	0 71	2062	0 0008	1296	1 67	7
MAGNUMCCGT	GAS	0 237	41 74	540 95	0 39	1 65	24	2003	0 71	2062	0 0008	1296	1 67	7
PHOENIXCCGT	GAS	0 237	41 74	540 95	0 39	1 65	170	2003	0 71	2062	0 0008	1296	1 67	7
AURIYA IICCGT 6	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
ANTA IICCGT 6	GAS	0 237	41 74	540 95	0 39	1 65	104	2003	0 71	2062	0 0008	1296	1 67	7
DHOLPURCCGT	GAS	0 237	41 74	540 95	0 39	1 65	233	2003	0 71	2062	0 0008	1296	1 67	7
SURATGARH II	COAL	0 812	13 49	1131 39	8 12	2 76	226	2004	0 71	2762	0 0012	864	2	5
SURATGARH II	COAL	0 812	13 49	1131 39	8 12	2 76	226	2004	0 71	2762	0 0012	864	2	5
MATHANIACCGT	GAS	0 237	41 74	540 95	0 39	1 65	34	2003	0 71	2062	0 0008	1296	1 67	7

MATHANIACCGT	GAS	0 237	41 74	540 95	0 39	1 65	34	2003	0 71	2062	0 0008	1296	1 67	7
MATHANIACCGT	GAS	0 237	41 74	540 95	0 39	1 65	68	2003	0 71	2062	0 0008	1296	1 67	7

Fuel consumption rate unit for coal is 1000 Kg/MWh

for gas is 1000 m^3/MWh

for nuclear is 1000 gm/MWh

for oil is 1000 LT/MWh

Minimum operating capacity for all the plants are taken as 30% of the Installed capacity

Table A 7 Existing Hydro Power Plant Data

NAME	Capacity (MW)	EA year	Availibility	Opearting Cost (000 $/ MWh)	Fixed O&M cost (000 $/ MWmonth)	Energy Season1 (MWh)	Energy Season2 (MWh)
W Y CANAL 1	8	2003	0 87	0	1 39	11000	31000
W Y CANAL 2	8	2003	0 87	0	1 39	11000	31000
W Y CANAL 3	8	2003	0 87	0	1 39	11000	31000
W Y CANAL 4	8	2003	0 87	0	1 39	11000	31000
W Y CANAL 5	8	2003	0 87	0	1 39	11000	31000
W Y CANAL 6	8	2003	0 87	0	1 39	11000	31000
ANDHRAU 1 3	17	2003	0 87	0	1 39	24000	33000
HPSMALL	9	2003	0 87	0	1 39	36000	57000
BAIRASIUL 1	60	2003	0 87	0	1 39	57000	190000
BAIRASIUL 2	60	2003	0 87	0	1 39	57000	191000
BAIRASIUL 3	60	2003	0 87	0	1 39	57000	190000
BANER	12	2003	0 87	0	1 39	14000	23000
THIROT	4 5	2003	0 87	0	1 39	19000	29000
GAJ	10 5	2003	0 87	0	1 39	5000	9000
BASSI 1	15	2003	0 87	0	1 39	28000	49000
BASSI 2	15	2003	0 87	0	1 39	28000	49000
BASSI 3	15	2003	0 87	0	1 39	28000	49000
BASSI 4	15	2003	0 87	0	1 39	28000	49000
BINWA	6	2003	0 87	0	1 39	14000	27000
CHAMERA I 1	180	2003	0 87	0	1 39	314000	400000
CHAMERA I 2	180	2003	0 87	0	1 39	314000	400000
CHAMERA I 3	180	2003	0 87	0	1 39	315000	400000
GIRIBATA 1	30	2003	0 87	0	1 39	48000	77000
GIRIBATA 2	30	2003	0 87	0	1 39	48000	77000
SANJAYBHAB A 1	40	2003	0 87	0	1 39	78000	113000
SANJAYBHAB A 2	40	2003	0 87	0	1 39	78000	113000
SANJAYBHAB A 3	40	2003	0 87	0	1 39	79000	113000
CHENANI	23	2003	0 87	0	1 39	30000	60000
GANDERBAL	15	2003	0 87	0	1 39	13000	26000
J&K SMALL	6	2003	0 87	0	1 39	5000	9000
KARGIL	4	2003	0 87	0	1 39	5000	9000
LOWERJHELU M	105	2003	0 87	0	1 39	171000	362000
MOHORA	9	2003	0 87	0	1 39	26000	53000
SALAL I 1	115	2003	0 87	0	1 39	339000	508000
SALAL I 2	115	2003	0 87	0	1 39	339000	508000
SALAL I 3	115	2003	0 87	0	1 39	339000	509000
SALAL II 1	115	2003	0 87	0	1 39	142000	212000
SALAL II 2	115	2003	0 87	0	1 39	142000	212000
SALAL II 3	115	2003	0 87	0	1 39	142000	213000
UPPERSINDH I	22 6	2003	0 87	0	1 39	33000	68000
URI 1	120	2003	0 87	0	1 39	175000	407000
URI 2	120	2003	0 87	0	1 39	175000	407000
URI 3	120	2003	0 87	0	1 39	5000	407000
URI 4	120	2003	0 87	0	1 39	175000	407000

ANANDPURSA HIB1	34	2003	0 87	0	1 39	61000	166000
ANANDPURSA HIB2	34	2003	0 87	0	1 39	61000	166000
ANANDPURSA HIB3	34	2003	0 87	0	1 39	61000	166000
ANANDPURSA HIB4	34	2003	0 87	0	1 39	62000	166000
BEASDEHAR 1	165	2003	0 87	0	1 39	197000	367000
BEASDEHAR 2	165	2003	0 87	0	1 39	197000	367000
BEASDEHAR 3	165	2003	0 87	0	1 39	197000	367000
BEASDEHAR 4	165	2003	0 87	0	1 39	197000	367000
BEASDEHAR 5	165	2003	0 87	0	1 39	197000	367000
BEASDEHAR 6	165	2003	0 87	0	1 39	198000	367000
BEASPONG 1	60	2003	0 87	0	1 39	84000	226000
BEASPONG 2	60	2003	0 87	0	1 39	84000	226000
BEASPONG 3	60	2003	0 87	0	1 39	84000	226000
BEASPONG 4	60	2003	0 87	0	1 39	84000	226000
BEASPONG 5	60	2003	0 87	0	1 39	84000	226000
BEASPONG 6	60	2003	0 87	0	1 39	84000	226000
BHAKRA(LB) 1	108	2003	0 87	0	1 39	156000	346000
BHAKRA(LB) 2	108	2003	0 87	0	1 39	156000	346000
BHAKRA(LB) 3	108	2003	0 87	0	1 39	156000	346000
BHAKRA(LB) 4	108	2003	0 87	0	1 39	156000	347000
BHAKRA(LB) 5	108	2003	0 87	0	1 39	156000	347000
BHAKRA(RB) 1	142	2003	0 87	0	1 39	205000	455000
BHAKRA(RB) 2	142	2003	0 87	0	1 39	205000	455000
BHAKRA(RB) 3	142	2003	0 87	0	1 39	205000	455000
BHAKRA(RB) 4	142	2003	0 87	0	1 39	205000	455000
BHAKRA(RB) 5	142	2003	0 87	0	1 39	205000	455000
GANGUWAL 1	29	2003	0 87	0	1 39	43000	150000
GANGUWAL 2	25	2003	0 87	0	1 39	43000	150000
GANGUWAL 3	24	2003	0 87	0	1 39	43000	150000
KOTLA 1	29	2003	0 87	0	1 39	43000	150000
KOTLA 2	25	2003	0 87	0	1 39	43000	150000
KOTLA 3	24	2003	0 87	0	1 39	43000	150000
MUKERIAN 1	15	2003	0 87	0	1 39	27000	71000
MUKERIAN 2	15	2003	0 87	0	1 39	27000	71000
MUKERIAN 3	15	2003	0 87	0	1 39	27000	71000
MUKERIAN 4	15	2003	0 87	0	1 39	27000	71000
MUKERIAN 5	15	2003	0 87	0	1 39	27000	71000
MUKERIAN 6	15	2003	0 87	0	1 39	27000	71000
MUKERIAN 7	20	2003	0 87	0	1 39	36000	93000
MUKERIAN 8	19	2003	0 87	0	1 39	36000	93000
MUKERIAN 9	20	2003	0 87	0	1 39	36000	93000
MUKERIAN 10	19	2003	0 87	0	1 39	36000	93000
MUKERIAN 11	20	2003	0 87	0	1 39	36000	93000
MUKERIAN 12	19	2003	0 87	0	1 39	36000	93000
SHANAN 1	15	2003	0 87	0	1 39	35000	60000
SHANAN 2	15	2003	0 87	0	1 39	35000	60000
SHANAN 3	15	2003	0 87	0	1 39	36000	60000
SHANAN 4	15	2003	0 87	0	1 39	36000	60000
SHANAN 5	50	2003	0 87	0	1 39	70000	120000
UBDC 1	15	2003	0 87	0	1 39	22000	21000
UBDC 2	15	2003	0 87	0	1 39	22000	21000
UBDC 3	15	2003	0 87	0	1 39	22000	21000

UBDC 4	15	2003	0 87	0	1 39	22000	21000
UBDC 5	15	2003	0 87	0	1 39	22000	21000
UBDC 6	15	2003	0 87	0	1 39	22000	22000
ANOOPGARH	9	2003	0 87	0	1 39	0	4000
JAWAHARSAG AR	99	2003	0 87	0	1 39	82000	348000
MAHI 1	25	2003	0 87	0	1 39	13000	55000
MAHI 2	25	2003	0 87	0	1 39	13000	57000
MAHI 3	45	2003	0 87	0	1 39	22000	95000
MAHI 4	45	2003	0 87	0	1 39	22000	95000
R P SAGAR	172	2003	0 87	0	1 39	91000	513000
RAJ SMALL	14	2003	0 87	0	1 39	0	9000
CHIBRO 1	60	2003	0 87	0	1 39	87000	147000
CHIBRO 2	60	2003	0 87	0	1 39	87000	147000
CHIBRO 3	60	2003	0 87	0	1 39	87000	147000
CHIBRO 4	60	2003	0 87	0	1 39	87000	147000
DHAKRANI 1	11	2003	0 87	0	1 39	16000	37000
DHAKRANI 2	11	2003	0 87	0	1 39	16000	37000
DHAKRANI 3	12	2003	0 87	0	1 39	16000	37000
DHALIPUR 1	17	2003	0 87	0	1 39	27000	63000
DHALIPUR 2	17	2003	0 87	0	1 39	27000	63000
DHALIPUR 3	17	2003	0 87	0	1 39	27000	64000
KHARA 1	24	2003	0 87	0	1 39	41000	91000
KHARA 2	24	2003	0 87	0	1 39	41000	91000
KHARA 3	24	2003	0 87	0	1 39	41000	91000
KHATIMAGAN GA	41 4	2003	0 87	0	1 39	59000	139000
KHODRI 1	30	2003	0 87	0	1 39	38000	71000
KHODRI 2	30	2003	0 87	0	1 39	38000	71000
KHODRI 3	30	2003	0 87	0	1 39	39000	71000
KHODRI 4	30	2003	0 87	0	1 39	39000	71000
KULHALST IV 1	10	2003	0 87	0	1 39	16000	37000
KULHALST IV 2	10	2003	0 87	0	1 39	16000	37000
KULHALST IV 3	10	2003	0 87	0	1 39	16000	37000
CHILLA 1	36	2003	0 87	0	1 39	52000	120000
CHILLA 2	36	2003	0 87	0	1 39	52000	120000
CHILLA 3	36	2003	0 87	0	1 39	52000	121000
CHILLA 4	36	2003	0 87	0	1 39	52000	121000
MANERIBHALI I1	30	2003	0 87	0	1 39	19000	99000
MANERIBHALI I2	30	2003	0 87	0	1 39	19000	99000
MANERIBHALI I3	30	2003	0 87	0	1 39	19000	99000
MATATILA 1	10	2003	0 87	0	1 39	16000	27000
MATATILA 2	10	2003	0 87	0	1 39	16000	27000
MATATILA 3	10	2003	0 87	0	1 39	17000	27000
OBRA 1 H	33	2003	0 87	0	1 39	26000	100000
OBRA 2 H	33	2003	0 87	0	1 39	26000	100000
OBRA 3 H	33	2003	0 87	0	1 39	26000	100000
RAMGANGA 1	66	2003	0 87	0	1 39	0	98000
RAMGANGA 2	66	2003	0 87	0	1 39	0	98000
RAMGANGA 3	66	2003	0 87	0	1 39	0	99000
RIHAND 1	50	2003	0 87	0	1 39	34000	138000
RIHAND 2	50	2003	0 87	0	1 39	34000	138000

RIHAND 3	50	2003	0 87	0	1 39	34000	137000
RIHAND 4	50	2003	0 87	0	1 39	34000	137000
RIHAND 5	50	2003	0 87	0	1 39	34000	137000
RIHAND 6	50	2003	0 87	0	1 39	34000	137000
TANAKPUR 1	30	2003	0 87	0	1 39	41000	69000
TANAKPUR 2	30	2003	0 87	0	1 39	41000	69000
TANAKPUR 3	30	2003	0 87	0	1 39	41000	69000
GANGACANAL	45 2	2003	0 87	0	1 39	32000	118000
SOBLA	6	2003	0 87	0	1 39	0	53000
TANAKPUR 4	30	2003	0 87	0	1 39	41000	70000
DADUPUR	6	2003	0 87	0	1 39	5000	13000
W Y C II	16	2003	0 87	0	1 39	16000	48000
BASPAII 1	100	2003	0 87	0	1 39	161000	241000
BASPAII 2	100	2003	0 87	0	1 39	161000	241000
BASPAII 3	100	2003	0 87	0	1 39	161000	241000
CHAMERA II 1	100	2004	0 87	0	1 39	170000	254000
CHAMERA II 2	100	2004	0 87	0	1 39	169000	254000
CHAMERA II 3	100	2004	0 87	0	1 39	169000	254000
KOLDAM 1	200	2006	0 87	0	1 39	307000	461000
KOLDAM 2	200	2006	0 87	0	1 39	307000	461000
KOLDAM 3	200	2007	0 87	0	1 39	307000	461000
KOLDAM 4	200	2007	0 87	0	1 39	307000	461000
LARJI1 3	126	2004	0 87	0	1 39	131000	196000
GHANVI	22 5	2003	0 87	0	1 39	18000	26000
NATHPAJHAKRI 1&2	500	2003	0 87	0	1 39	663000	996000
NATHPAJHAKRI 3	250	2003	0 87	0	1 39	332000	497000
NATHPAJHAKRI 4	250	2003	0 87	0	1 39	332000	497000
NATHPAJHAKRI 5	250	2003	0 87	0	1 39	332000	497000
NATHPAJHAKRI 6	250	2003	0 87	0	1 39	332000	497000
PARVATI II 1	200	2006	0 87	0	1 39	318000	476000
PARVATI II 2	200	2006	0 87	0	1 39	318000	476000
PARVATI II 3	200	2007	0 87	0	1 39	318000	476000
PARVATI II 4	200	2007	0 87	0	1 39	318000	476000
CHENANI II	7 5	2003	0 87	0	1 39	6000	12000
DULHASTI 1	130	2003	0 87	0	1 39	257000	386000
DULHASTI 2	130	2003	0 87	0	1 39	257000	386000
DULHASTI 3	130	2003	0 87	0	1 39	257000	386000
PAHALGAON	3	2003	0 87	0	1 39	2000	3000
PARNAIHEP1	12 5	2003	0 87	0	1 39	26000	54000
SEWA III	9	2003	0 87	0	1 39	16000	31000
UPPERSINDH II	70	2003	0 87	0	1 39	53000	109000
UPPERSINDH III	35	2003	0 87	0	1 39	27000	54000
SHAHPURKHANDI	40	2004	0 87	0	1 39	51000	115000
SYLCANAL	50	2003	0 87	0	1 39	127000	190000
THEINDAM 1	150	2003	0 87	0	1 39	105000	235000
THEINDAM 2	150	2003	0 87	0	1 39	106000	235000
THEINDAM 3	150	2003	0 87	0	1 39	106000	235000
THEINDAM 4	150	2003	0 87	0	1 39	106000	235000
JAKHAM	5	2003	0 87	0	1 39	5000	22000
KATAPATHAR	19	2006	0 87	0	1 39	19000	35000

HE							
DHAULIGANG A I 1	140	2004	0 87	0	1 39	198000	369000
DHAULIGANG A I 2	140	2004	0 87	0	1 39	198000	369000
KOTESHWAR 1	100	2005	0 87	0	1 39	108000	200000
KOTESHWAR 2	100	2005	0 87	0	1 39	108000	200000
KOTESHWAR 3	100	2006	0 87	0	1 39	108000	200000
KOTESHWAR 4	100	2006	0 87	0	1 39	108000	200000
LAKHWAR[VYASI]1	100	2005	0 87	0	1 39	55000	103000
LAKHWAR[VYASI]2	100	2005	0 87	0	1 39	55000	103000
MANERIBH II 1	76	2004	0 87	0	1 39	82000	152000
MANERIBH II 2	76	2004	0 87	0	1 39	82000	152000
MANERIBH II 3	76	2004	0 87	0	1 39	82000	152000
MANERIBH II 4	76	2004	0 87	0	1 39	82000	152000
RAJGHAT50/	22	2003	0 87	0	1 39	15000	29000
TEHRISTI 1	250	2003	0 87	0	1 39	251000	466000
TEHRISTI 2	250	2003	0 87	0	1 39	251000	466000
TEHRISTI 3	250	2003	0 87	0	1 39	251000	466000
TEHRISTI 4	250	2003	0 87	0	1 39	251000	466000
VISHNUPRAYAG 1	100	2003	0 87	0	1 39	118000	220000
VISHNUPRAYAG 2	100	2003	0 87	0	1 39	118000	220000
VISHNUPRAYAG 3	100	2003	0 87	0	1 39	118000	220000
VISHNUPRAYAG 4	100	2003	0 87	0	1 39	118000	220000
VYASI[LAKWAR]	120	2004	0 87	0	1 39	132000	244000
LAKHWARVYASI3	100	2005	0 87	0	1 39	55000	103000
PARNAIHEP2	12 5	2004	0 87	0	1 39	26000	54000
PARNAIHEP3	12 5	2004	0 87	0	1 39	26000	54000
TEHRIII 1	250	2005	0 87	0	1 39	251000	465000
TEHRIII 2	250	2005	0 87	0	1 39	251000	465000
TEHRIII 3	250	2006	0 87	0	1 39	251000	465000
TEHRI II 4	250	2006	0 87	0	1 39	251000	465000
SHAHPURKHANDI	40	2004	0 87	0	1 39	51000	114000
SHAHPURKHANDI	40	2004	0 87	0	1 39	51000	114000
SHAHPURKHANDI	40	200[illegible]	0 87	0	1 39	51000	114000
SHAHPURKHANDI	8	2004	0 87	0	1 39	10000	23000
MALANAHEP	86	2004	0 87	0	1 39	123000	185000

ANNEX B

Table B 1 Plant Type Data Form

TYPE	NAME
1	CONVENTIONAL COAL
2	COMBINED CYCLE GAS TURBINE
3	NUCLEAR
4	LIGNITE
5	PFBC
6	IGCC

Table B 2 Candidate Thermal Power Plant Data Form

Candidate Thermal Plant No	1	2	3	4	5
Name	COAL 500	CCGT 250	NUCLE 500	PFBC 500	IGCC 500
Used Fuel Type	COAL	GAS	NUCLE AR	COAL	COAL
Fuel Consumption Rate Unit	000 Kg/KWh	000 Kg/ MWh	000 Kg/ MWh	000 Kg/ MWh	000 Kg/ MWh
Fuel Consumption	0 7	0 2	0 00027	0 51	0 51
Calorific Value (KBtu/Kg)	13 5	34 52	40635	15 56	15 56
CO_2 Emission (Kg/MWh)	1026	550	0	907	551
SO_2 Emission (Kg/MWh)	6	0 4	0	0 255	0 235
NO_x Emission (Kg/MWh)	2 5	1 64	0	0 6	0 6
Capacity (MW)	500	250	500	450	400
Minimum Operating Capacity (MW)	150	75	125	150	150
Earliest Available Year	1	1	4	3	3
Annual Allowable Max Unit	150	75	4	10	10
Availability	0 71	0 8	0 58	0 85	0 85
Unit Depreciable Capital Cost (000 $)	450000	175000	600000	475000	500000
Unit Non Depreciable Capital Cost (000 $)	50000	19500	66000	52750	55550
Heat Rate (Mcal/MWh)	2500	2062	2777	2013	1850
Operating Cost (000 $/MWh)	0 0012	0 0008	0 0015	0 0012	0 00127
Transmission Loss Rate	0 04	0 04	0 04	0 04	0 04
Annual Maintenance Hours	864	1296	896	864	864
Unit Life Time	30	25	30	30	30
Fixed Oper & Maint Cost (000 $/MWmonth)	2	1 67	2 7	2 2	2 32
Number of the Fuel Type	4	7	8	4	4
Number of the Plant Type	1	2	3	5	6
Plant Site No	0	0	0	0	0
Minimum Selected Units in Year 2003	2	2	0	0	0
Max Possible Incremental Units in Year 2003	150	75	0	0	0
Minimum Selected Units in Year 2004	2	2	0	0	0
Max Possible Incremental Units in Year 2004	150	75	0	0	0
Minimum Selected Units in Year 2005	2	2	0	2	2
Max Possible Incremental Units in Year 2005	150	75	0	10	10
Minimum Selected Units in Year 2006	2	2	0	2	2
Max Possible Incremental Units in Year 2006	150	75	0	10	10
Minimum Selected Units in Year 2007	2	2	0	2	2
Max Possible Incremental Units in Year 2007	150	75	0	10	10
Minimum Selected Units in Year 2008	2	2	2	2	2
Max Possible Incremental Units in Year 2008	150	75	4	10	10
Minimum Selected Units in Year 2009	2	2	2	2	2

Max Possible Incremental Units in Year 2009	150	75	4	10	10
Minimum Selected Units in Year 20010	2	2	2	2	2
Max Possible Incremental Units in Year 2010	150	75	4	10	10
Minimum Selected Units in Year 2011	2	2	2	2	2
Max Possible Incremental Units in Year 2011	150	75	4	10	10
Minimum Selected Units in Year 2012	2	2	2	2	2
Max Possible Incremental Units in Year 2012	150	75	4	10	10
Minimum Selected Units in Year 2013	5	2	2	2	2
Max Possible Incremental Units in Year 2013	150	75	4	10	10
Minimum Selected Units in Year 2014	5	2	2	2	2
Max Possible Incremental Units in Year 2014	150	75	4	10	10
Minimum Selected Units in Year 2015	2	2	2	2	2
Max Possible Incremental Units in Year 2015	150	75	4	10	10
Minimum Selected Units in Year 2016	2	2	2	2	2
Max Possible Incremental Units in Year 2016	150	75	4	10	10
Minimum selected Units in Year 2017	2	2	2	2	2
Max Possible Incremental Units in Year 2017	150	75	4	10	10

ANNEX C

Table C 1 Basic Data Form

Optimal Output File	C \ullash\out lp

Base Year	Starting Year	No of Years	No of Seasons	No of Blocks	Discount Factor	No of Fuel Type	No of Plant Types
1998	2003	15	2	20	1 1	10	6

Emission Constraints	Solver Type	DSM Case
YES	CPLEX	No Restriction

Existing Plants			Candidate Plants			DSM Option	External Suppliers	GROUPS		
Thermal	Hydro	Pump Stor	Thermal	Hydro	Pump Stor			Thermal	Hydro	DSM
160	230	0	5	6	0	0	0	0	0	0

No of hours of a block of the daily load curve

Block	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Value	1	1	2	1	1	1	1	1	1	1	1	1	4	1	1	1	1	1	1	1

No of Days of season in a year

Season	1	2
Value	92	273

Table C 2 Emission Data Form

Expected CO_2 Emission Limit (Unit = Mtons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	195 97	205 01	221 15	231 82	250 45	262 44	286 01	305 64	331 37	354 83	-84 5	411 62	444 62	478 78	514 23

Total CO Emission Limit During Planning Period | 0 |

Expected SO_2 Emission Limit (Unit = Ktons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total SO_2 Emission Limit During Planning Period | 0 |

Expected NO Emission Limit (Unit = Ktons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total SO_2 Emission Limit During Planning Period | 0 |

ANNEX D

Table D 1 Emission Data Form

Expected CO_2 Emission Limit (Unit = Mtons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	186 65	194 23	209 51	219 62	237 25	248 62	270 95	289 55	313 92	336 15	364 26	389 95	421 22	453 58	487 16

Total CO_2 Emission Limit During Planning Period   0

Expected SO_2 Emission Limit (Unit = Ktons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total SO_2 Emission Limit During Planning Period   0

Expected NO Emission Limit (Unit = Ktons)

Year	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Value	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total SO_2 Emission Limit During Planning Period   0

ANNEX E

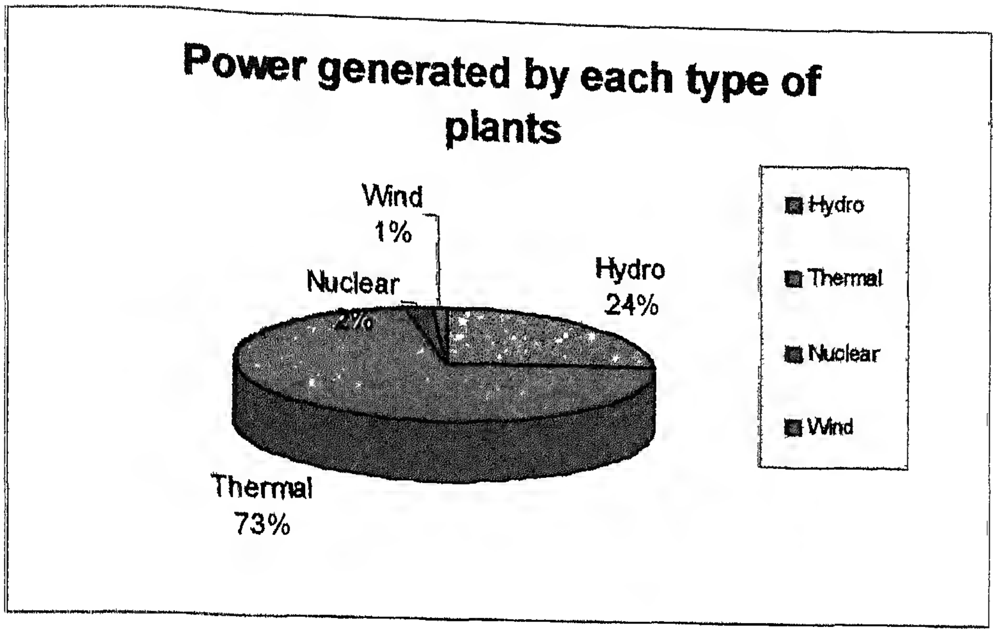

Figure-1 Power generated by each type of plants in India

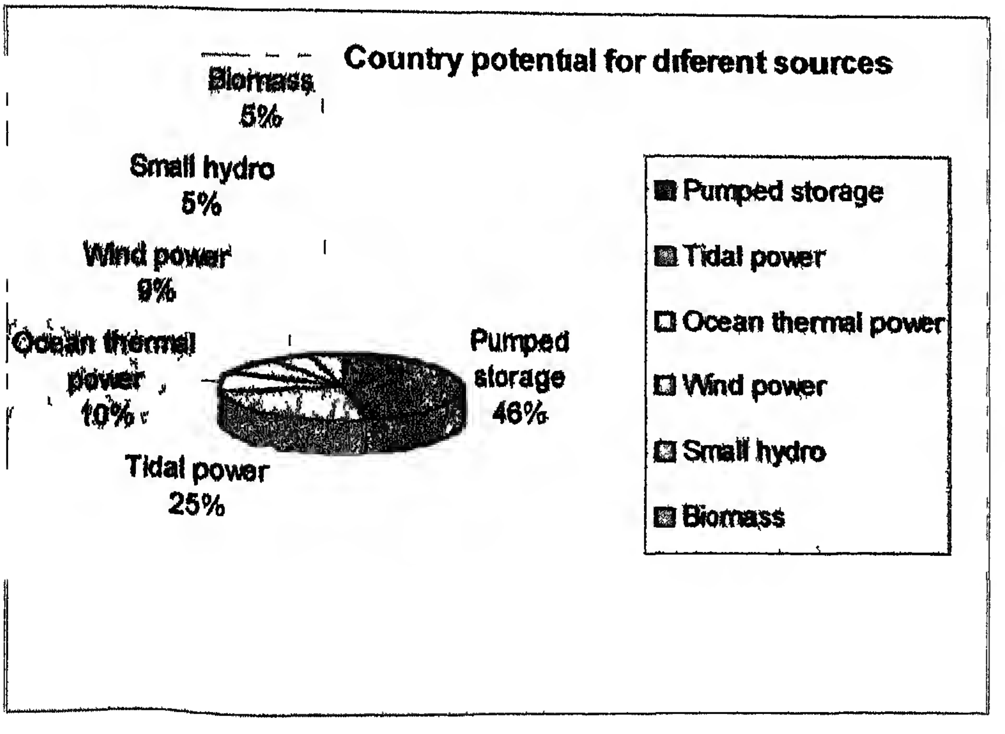

Figure 2 Countries potential for different sources

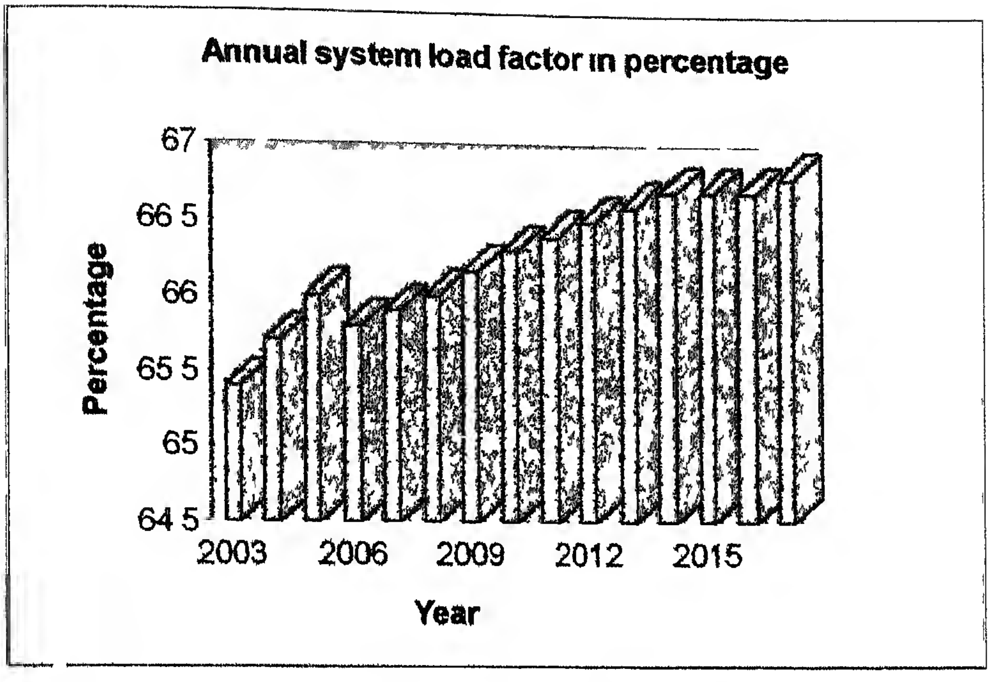

Figure 3 Annual system load factor for whole planning horizon

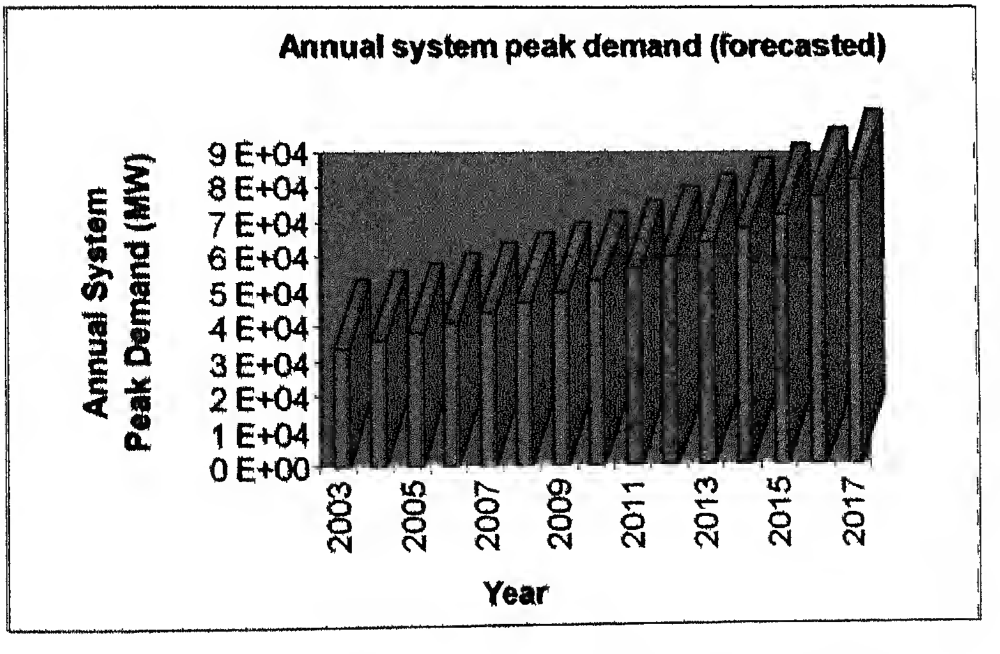

Figure 4 Annual system peak demand (forecasted) for whole planning horizon

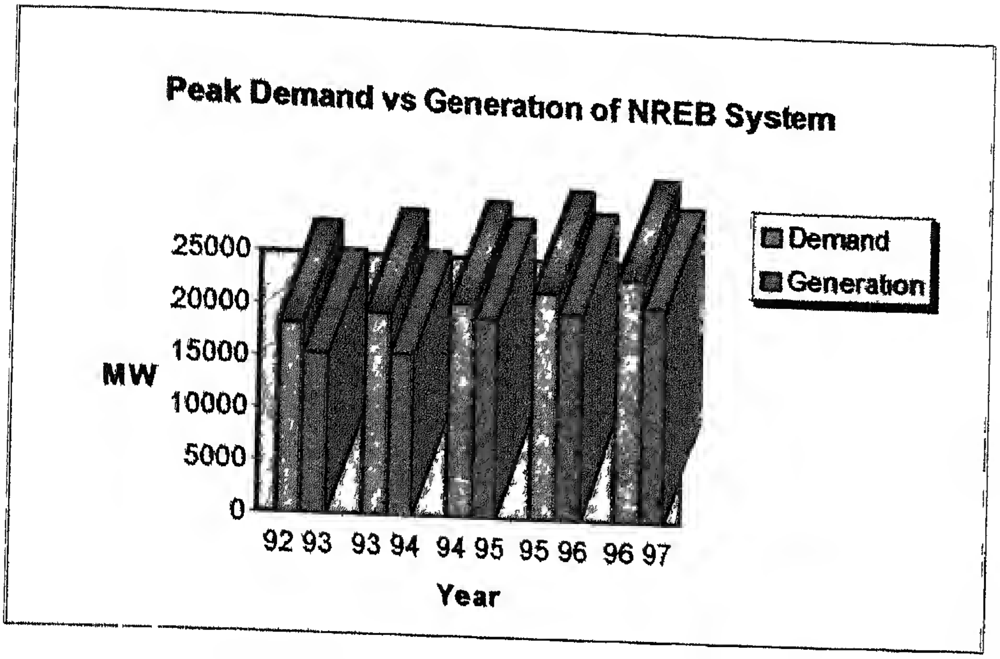

Figure 5 Generation vs Demand in NREB system

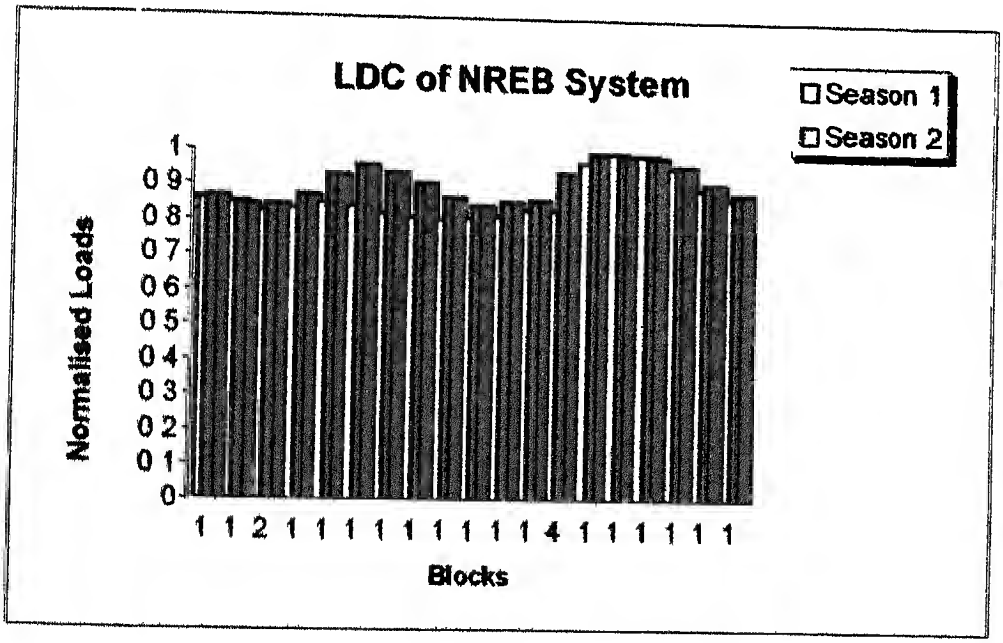

Figure 6 Load Duration Curve for both seasons in India

Table E 1 Utility boiler source performance

		Emission Factor (kg/TJ energy input)
Basic Technology	**Configuration**	**NO_x**
Coal		
Pulverized Bituminous Combustion	Dry Bottom wall fired	380
	Dry Bottom tangentially fired	250
	Wet Bottom	590
Bituminous Spreader Stokers	With and without re injection	240
Bituminous Fluidized Bed Combustion	Circulating Bed	68
	Bubbling Bed	270
Pulverized Lignite Combustion	Dry Bottom tangentially fired	130
	Dry Bottom wall fired	200
Natural Gas		
Large Gas Fired Gas Turbine > 3MW		190

REFERENCES

1 Activities Implemented Jointly Partnership for Climate and Development International Energy Agency 1997

2 Andrews J C and S Govil Regulating reform and Risk Management in the US Electricity Sector Energy Policy Vol 23 No 10 1995 pp 885 892

3 Asia Least cost Green House Gas Abatement Strategy (ALGAS) Project Unpublished Country Papers ALGAS Final Regional Workshop 12 14 Nov 1997 Manila

4 ASEAN Energy Review Asian EC Energy Management Training and Research Center (AEEMTRC) Jakarta 1996

5 Asian Institute of Technology Thailand Methodology Training Program October 18 22 1999

6 Brown M A Scenarios of US Carbon Reduction Potential Impact of Energy Efficient and Low Carbon Technologies by 2010 and beyond 1996 http //www ornl gov/ORNL/Energy Eff/CON444

7 Calthrop E and Madison D The Dose Response Function Approach to Modeling the Health Effects of Air Pollution Energy policy vol 24 No 7 1996 pp 599 607

8 Canadian Energy Research Institute and Tata Energy Research Institute (CERI/TERI) Planning for the Indian Power Sector Environmental and Development Considerations Tata Energy Research Institute India 1996

9 Central Electricity Authority (CEA) Fourth National Power Plan 1997 2012 CEA Government of India 1996

10 Chambers A IGCC Offers Diversity for Competitive Generation Power Engineering November 1997

11 Chattopadhya D and J K Parikh CO_2 Emission Reduction from the Power System in India Natural Resources Forum Vol 17 No 4 1993

12 Chowdhury B H Emission Control Alternatives for Electric Utility Power Plants Energy Sources Vol 18 pp 393 406 1996

13 Corman J and Paul, T C Power System for the 21st Century H Gas Turbine Combined Cycle GER 3935 GE Power Systems Schenectady NY 1995

14 Electricity Generating Authority of Thailand (EGAT) General Information EGAT Power Development Plan (PDP 95 01) EGAT Thailand 1995

15 Electricity Generating Authority of Thailand (EGAT) EGAT Power Development Plan EGAT Thailand 1997

16 Electricity Generating Authority of Thailand (EGAT) EGAT Power Development Plan (Revised PDP 99 01) General Information System Planning Department EGAT Thailand 1999

17 Electricity Meeting Needs with Least Environmental Impacts Thailand Environmental Institute 1995

18 Electricity Utilities Data Book for Asia and the Pacific Region Asian Development Bank Manila 1993

19 Energy Statistics and Balances of Non OECD Countries 1994 1995 International Energy Agency Paris 1997

20 Environmental Protection Act by Central Pollution Control Board New Delhi 1986

21 Fifteenth Electric Power Survey of India Published by CEA 1995

22 First Progress Report as project on Mitigation of GHG from the power sector I I T Kanpur and CEA New Delhi July 1999

23 Fourth National Power Plan 1997 2012 EPIS New Delhi

24 Hill L J Integrating Methods and Resource Selection in Electric Utility Planning Utilities Policy Vol 3 No 1 1993 pp 57 61

25 Hoog D T and A F Hobbs An Integrated Resource Planning Model considering Customer Value Emission and Regional Economic Impacts Energy Vol 18 No 11 1993 pp 1153 1160

26 India Power and Infrastructure Report April 1999

27 Intarapravich D Johnson C J Li B Long S Pezeshki Prawiraatmadja W tang F C and Wu K 1996 Asia Pacific Energy supply and Demand to 2010 Energy, Vol 21 No 11 1996 pp 1017 1039

28 Intergovernmental Panel on Climate Change (IPCC) Impacts Adaptation and Mitigation of Climate Scientific Technical Analysis Second Assessment Report of the IPCC Cambridge University Press 1996

29 International Atomic Energy Agency Expansion Planning for Electrical generating System A Guidebook International Atomic Energy Efficiency Vienna 1984

30 International Atomic Energy Agency (Wien Automatic System Planning Package (WASP) Volume 1 IAEA Vienna Austria 1995

31 Kane R and D W South Potential Fossil Energy Related Technology Options to Reduce Greenhouse Gas Emissions Energy Technologies for Reducing Emissions of Greenhouse Gases Proceeding of an Expert s Seminar Paris 12 14th April 1989

32 Kant R Economic Aspects of the Use of Beneficiated Coal for Thermal Power Stations Water and Energy 2001 International R&D Conference New Delhi India 1995

33 Kessler J B Seillo and Harpel Is Natural gas really the answer? Targeting Natural Gas in US Climate Change Mitigation Policy Energy Policy Vol 22 No 7 1994 pp 623 628

34 Kyoto Conference of the Parties third session 1 10 December 1997 Agenda item 5

35 Markandya A Environmental Cost and Power System Planning Utility Policy Strategy Performance and Regulation Vol 1 No 1 1995 pp 13 27

36 Mathur A Potential for Introducing Advanced Technology for Power Generation in India Proceedings of the Training Workshop on Environmental Issues Related to Electric Power Generation Project in India 4 6 March 1993 Jaipur India Published by ADB 1993

37 Maya R S and Fenhann J Methodological Lessons and Results from UNEPGHG Abatement Costing Studies Energy Policy Vol 22 No 11 1993 pp 955 963

38 Meier P and M Munasinghe Greenhouse Gas Emission Reduction A Case Study of Sri Lanka The Energy Journal Vol 6 No 4 1995 pp 79 107

39 MIT Energy Laboratory Electrical generation Analysis System (EGEAS) EPRIEL 2561 Final Report 1982

40 Mumtaz A Over view of WASP IV Additional Features Reports presented in the Regional Seminar to Exchange Information and Experience on National Efforts in Developing Countries Specific Database to Support Comparative Assessment AIT Bangkok May 1999

41 OECD Global Warming Economic Dimension and Policy Responses Paris 1995

42 Pabla A S Electrical Power System planning Macmillan India Limited 1996

43 Pearson P J G and R Foquett Energy Efficiency Economic Efficiency and Future CO_2 Emissions from the Developing World The Energy Journal Vol 17 No 4 1996

44 Power Line Vol 3 No 7 April 1999 issue

45 Power Supply Industry in India Highlights by Electric Power Information Society (EPIS) New Delhi March 1998

46 Reinheimer H 650 MW Combined Cycle Plant for Ganhda India Modern Power Systems September 1992 pp 47 56

47 Report on Perspective of National Power Development upto 2006 2007 CEA Sept 1991

48 Rose A Torries T and Labys W Clean Coal Technologies and Future Prospects for Coal Annual Review of Energy Environment Vol 16 1991 pp 59 90

49 Sarma E A S Maggo J N and Sachedeva A S India s Energy Scenario in 2020 Paper presented at the 17th congress of the World Energy Council held at Houston U S A Sept 1998

50 Shrestha R M and G R Timilsina Factors Affecting CO_2 Intensities of Power Sector in Asia A Divisia decomposition Analysis Energy Economics Vol 18 No 4 1996 pp 283 293

51 Shrestha R M H Samarakoon and R Shrestha Assessment of Efficient Demand and Supply Side Greenhouse Gas Mitigation from an Integrated Resource Planning Perspective Energy Program AIT Bangkok Submitted to Sida Sweden (1997)

52 Shrestha R M and S C Bhattacharya Technological and Policy Option to Reduce Acid Rain Causing Emission in Asia First National Workshop on Acid Rain and Emissions Reduction in Asia Organized by UNEP/EAP AP Sponsored by Asian Development Bank 1998

53 Tavoulareas E S and Charpentier J P Clean Coal Technologies for Developing Countries World Bank Technical Paper Number 186 Energy Series The World Bank Washington D C USA 1995

54 Toufiq A S Implication of Global Climate Change Concerns for Electricity Supply in the Asia Pacific Region Asia Pacific Electricity Development Specialist Group Meeting Ho Chi Minh City Vietnam 21 23 August 1995

55 United Nations Environmental Program (UNEP) Greenhouse Gas Mitigation Costing Studies UNEP Nairobi 1992

56 US Country Study Progiam (USCSP) Intenm Report on Clımate Change Country Studıes US Countiy Study Management Team Washıngton 1995

57 Van der Voort Donnı E Thonet E Boıs d Enghıen E Dechamps C and Guılmot JF Eneigy Supply Modellıng Package EFOM 12C Mark I Mathematıcal Descııptıon Commıssıon of the European Communıtıes Louvaın la Neuve Cabay EUR 8896 1984

58 Zhang Z X Cost Effectıveness Analysıs of Carbon Abatement Optıons ın Chına s Electııcıty Sector Energy Sources Vol 20 1998

A 130932

Date Slip

This book is to be returned on the date last stamped